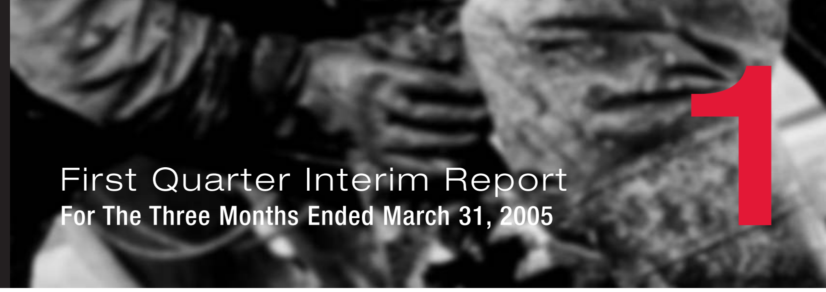
ARC ENERGY TRUST



First Quarter Interim Report

For The Three Months Ended March 31, 2005

1

	Three Months Ended March 31	
	2005	2004
FINANCIAL		
($CDN thousands, except per unit and per boe amounts)		
Revenue before royalties	**238,054**	205,594
Per unit [1]	**1.28**	1.14
Per boe	**47.74**	39.58
Cash flow [3]	**141,965**	108,014
Per unit [1]	**0.76**	0.60
Per boe	**28.47**	20.80
Net income [5]	**38,646**	39,460
Per unit [1] [5]	**0.21**	0.22
Cash distributions	**83,867**	81,215
Per unit [1]	**0.45**	0.45
Payout ratio [6]	**59%**	75%
Net debt outstanding [4]	**254,252**	284,001
OPERATING		
Production		
Crude oil (bbl/d)	**21,993**	23,663
Natural gas (mcf/d)	**176,073**	174,534
Natural gas liquids (bbl/d)	**4,072**	4,323
Total (boe/d)	**55,410**	57,075
Average prices [5]		
Crude oil ($/bbl)	**53.63**	40.41
Natural gas ($/mcf)	**7.20**	6.64
Natural gas liquids ($/bbl)	**46.57**	32.30
Oil equivalent ($/boe) [7]	**47.74**	39.58
Operating netback ($/boe)		
Commodity and other revenue (before hedging)	**47.74**	39.58
Transportation costs	**(0.72)**	(0.74)
Royalties	**(8.99)**	(7.46)
Operating costs	**(6.10)**	(6.45)
Netback (before hedging)	**31.93**	24.93
TRUST UNITS		
(thousands)		
Units outstanding, end of period	**186,623**	180,951
Units issuable for exchangeable shares	**2,986**	3,029
Total units outstanding and issuable for exchangeable shares, end of period	**189,609**	183,980
Weighted average units [2]	**186,224**	180,285
TRUST UNIT TRADING STATISTICS		
($CDN, except volumes) based on intra-day trading		
High	**20.40**	15.74
Low	**16.55**	13.50
Close	**18.15**	15.64
Average daily volume	**895,140**	501,643

(1) Per unit amounts (with the exception of per unit distributions) are based on weighted average units.
(2) Excludes trust units issuable for outstanding exchangeable shares at period end.
(3) Management uses cash flow to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital and expenditures on site restoration and reclamation.
(4) Net debt excludes unrealized commodity and foreign exchange contracts asset and liability, the deferred hedge loss and deferred commodity and foreign currency contracts.
(5) Net income and net income per unit for the first quarter of 2004 have been restated for the adoption of the new accounting standard for non-controlling interest in the fourth quarter of 2004. See Note 2 of the unaudited interim consolidated financial statements for details of the restatement.
(6) Cash distributions divided by cash flow from operations.
(7) Includes other revenue.

MESSAGE TO UNITHOLDERS

The oil and gas industry continued its full-out pace in the first quarter of 2005, with oil prices maintaining their historical high levels. As a result of high commodity prices for both oil and gas, ARC Energy Trust ("ARC" or the "Trust") realized record revenues and cash flows in the first quarter.

The WTI price reached a high of US$58.28 per barrel, closed the quarter at US$55.40 per barrel and is currently trading within this range. AECO gas prices traded in a range of $6.50 per mcf to $7.50 per mcf during the quarter. Storage levels for gas are higher this year than last year and more rigs are working, so high oil prices appear to be the main driver behind the high natural gas price. Forecasts from analysts and economists for commodity prices remain bullish in both the near and longer term. Consensus among analysts regarding future oil prices is that the WTI price should remain at or above current levels for the rest of the decade. Some analysts suggest a major upward price spike will be required to curtail demand to a level which can be met by declining supply. In this context speculation, strong demand growth and a volatile geopolitical environment should all contribute to maintaining the WTI price above US$50.00 per barrel and will likely contribute to significant price volatility in the future.

ARC continues to hedge a portion of its production to maintain stability in its distributions. We are maintaining our new hedging strategy that focuses on purchasing floors, which enables the Trust to participate in the up-side of higher commodity prices. This strategy allows ARC to participate at a higher commodity price on approximately 77 per cent of its production if commodity prices rise above forward price levels while providing downside protection on 49 per cent of production for the balance of 2005. ARC has hedged approximately 68 per cent of natural gas during the upcoming summer months. This percentage of hedged natural gas is higher than ARC would typically undertake, however, drilling activity is at record high levels and storage levels for gas are high compared to historic levels which could lead to a weaker Canadian natural gas price this summer even if U.S. gas prices remain relatively strong.

ARC realized record cash flow of $142 million ($0.76 per unit) in the first quarter and maintained distributions at the $0.15 per unit level. This decreased ARC's payout ratio to 59 per cent for the quarter and allowed ARC to fund its entire first quarter capital expenditure program of $52.5 million out of cash flow. The remaining cash flow was directed to ARC's reclamation fund and to debt repayment. ARC has a strong balance sheet as a result of the higher commodity prices with a net debt to annualized cash flow of 0.4 times and net debt to total capitalization of seven per cent. It is our view that at this point, ARC is somewhat under-leveraged, however, we fundamentally believe that during times of high commodity prices we should maintain a strong balance sheet as a drop in commodity prices could increase our debt to cash flow very quickly.

ARC will focus on executing its planned internal development program of drilling and development for the remainder of the year and will continue to review acquisition opportunities that would strategically benefit the Trust in the long-term and provide value to our unitholders.

John P. Dielwart
Director, President and
Chief Executive Officer

ACCOMPLISHMENTS / FINANCIAL UPDATE

- Production averaged 55,410 boe per day in the first quarter of 2005, three per cent lower than the 57,075 boe per day production in the first quarter of 2004 due to the dispositions of non-core properties with production of 1,800 boe/d in the second quarter of 2004. The Trust was very active in the first quarter, spending $52.5 million ($32 million on operated properties) on capital development and drilling 13 net wells on operated properties. Production volumes for 2005 are expected to average approximately 54,800 boe per day.

- ARC realized record cash flow of $142 million ($0.76 per trust unit) in the first quarter of 2005 compared to $108 million ($0.60 per trust unit) in the first quarter of 2004. The 31 per cent increase in 2005 cash flow relative to 2004 was due to the significant increase in commodity prices which commenced in the latter half of 2004 and have continued through the first quarter of 2005.

- West Texas Intermediate ("WTI") averaged US$49.90 per barrel during the first quarter and closed the quarter at US$55.40 per barrel while the first quarter AECO natural gas price averaged $6.69 per mcf.

- The Trust declared cash distributions of $83.9 million ($0.45 per trust unit) in the first quarter of 2005, resulting in a payout ratio of 59 per cent. The remaining $58.1 million of first quarter 2005 cash flow was used to fund the entire first quarter capital expenditure program of $52.5 million, make a $1.7 million contribution, including interest, to the reclamation fund, and apply $3.9 million to working capital.

- The Trust realized an operating netback, before hedging, of $31.93 per boe in the first quarter of 2005 compared to $24.93 in the first quarter of 2004. The netback of $31.93 per boe represents the highest in the Trust's history and is due to strong commodity prices and cost management. The continued focus on cost control resulted in reported operating costs of $6.10 per boe in the first quarter of 2005 compared to $6.45 per boe in the first quarter of 2004.

- During the first quarter, the Trust continued with its revised hedging strategy that results in participation in rising commodity prices while limiting the exposure to commodity price downturns. Cash hedging losses in the quarter were $7.3 million or three per cent of revenue compared to $13.6 million in the first quarter of 2004, which represented 6.6 per cent of first quarter 2004 revenue. For the remainder of 2005, approximately 77 per cent of ARC's production will participate in commodity price increases with downside protection on approximately 49 per cent of the Trust's production, well above budgeted levels required to maintain distributions.

- Net income prior to the unrealized hedging loss, after associated future income tax recoveries, equated to 58 per cent of first quarter 2005 cash flow compared to 51 per cent of cash flow for the first quarter of 2004. The unrealized hedge loss, net of associated future income tax recoveries, resulted in a reduction in first quarter 2005 net income from $82.5 million to $38.6 million (net income for the first quarter of 2004 was reduced from $54.9 million to $39.5 million as a result of the $23.6 million unrealized hedging loss net of associated future income tax recoveries).

ACCOMPLISHMENTS / FINANCIAL UPDATE (cont'd)

- The Trust's balance sheet continued to strengthen in 2005 with the Trust's net debt to annualized cash flow at 0.4 times as at March 31, 2005 and net debt to total capitalization of seven per cent. The strength in the balance sheet was attributed to the strong commodity prices during 2005 that enabled the Trust to fund 100 per cent of its first quarter capital expenditure program with cash flow rather than debt.

- On March 23, 2005, Saskatchewan Finance passed its 2005 budget that included an amendment to subject Trusts to the Corporation Capital Tax Resource Surcharge ("Resource Surcharge") effective April 1, 2005. Previously, the resource surcharge did not apply to resource trusts and therefore the Trust was not previously impacted by the resource surcharge. The resource surcharge is calculated based on a rate applicable to working interest oil and natural gas revenue earned in Saskatchewan at a rate of 3.6 per cent on revenue from wells drilled prior to October 1, 2002 and a rate of two per cent on revenue from wells drilled on or after October 1, 2002. As approximately 25 per cent of the Trust's current operations are in Saskatchewan, the Trust has estimated that cash flow will be reduced by approximately $2 million per quarter, commencing in the second quarter of 2005.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2004.

This MD&A was written on April 30, 2005.

Management uses cash flow to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles, ("GAAP") and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this MD&A are based on cash flow before changes in non-cash working capital and expenditures on site restoration and reclamation.

Management uses certain key performance indicators ("KPI's") and industry benchmarks such as operating netbacks ("netbacks"), total capitalization and payout ratios to analyze financial and operating performance. These KPI's and benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

This discussion and analysis contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of ARC Energy Trust ("ARC" or "the Trust"). The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties, including the business risks discussed in the MD&A as at and for the year ended December 31, 2004, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted.

The Trust implemented new accounting policies in the fourth quarter of 2004 pursuant to requirements of the Canadian Institute of Chartered Accountants ("CICA"). Certain amounts presented for comparative purposes have been restated as a result of the retroactive application of these new policies and instruments. See "Impact of New Accounting Policies" in this MD&A for a detailed description of the impact on reported results.

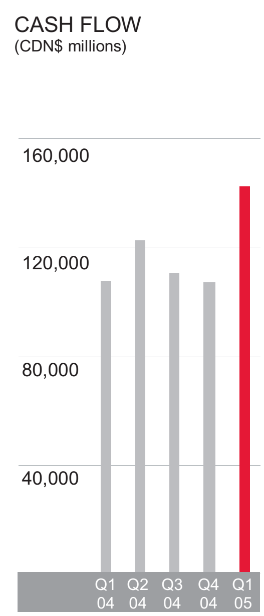
Highlights

(CDN$ millions, except per unit and volume data)	Three Months Ended March 31 2005	2004	% Change
Cash flow from operations	**142.0**	108.0	31
Cash flow from operations per unit	**0.76**	0.60	27
Net income before taxes (1)	**9.8**	24.4	(60)
Net income	**38.6**	39.5	(2)
Distributions per unit	**0.45**	0.45	-
Payout ratio per cent (2)	**59**	75	(21)
Daily production (boe/d) (3)	**55,410**	57,075	(3)

(1) Represents net income after non-controlling interest and before the future income tax recovery and capital taxes.
(2) Based on cash distributions divided by cash flow from operations.
(3) Reported production amount is based on company interest before royalty burdens.

Net Income

Net income in the first quarter of 2005 of $38.6 million decreased by two per cent from net income of $39.5 million in the first quarter of 2004. The decline in net income in the first quarter of 2005 was due to an unrealized hedging loss of $43.9 million ($66.7 million before a future income tax recovery of $22.8 million) compared to an unrealized loss of $15.4 million ($23.6 million before a future income tax recovery of $8.2 million) in the first quarter of 2004. Prior to the unrealized hedging loss, net income was $82.5 million and $54.9 million, respectively, in the first quarter of 2005 and 2004, representing an increase in first quarter 2005 net income of 50 per cent relative to 2004.



Cash Flow from Operations

Cash flow from operations increased by 31 per cent in the first quarter of 2005 to $142 million from $108 million in the first quarter of 2004. The increase in 2005 cash flow from operations was the result of higher commodity prices, lower operating costs and reduced realized losses under the Trust's hedging program. Per unit cash flow from operations increased 27 per cent to $0.76 per trust unit from $0.60 per trust unit in the first quarter of 2004. The first quarter 2005 cash flow from operations included a cash loss of $7.3 million on commodity and foreign currency contracts compared to a cash loss of $13.6 million in the first quarter of 2004.

Following is a summary of variances in cash flow from operations for the first quarter of 2004 relative to the first quarter of 2005:

	$ millions	$ per trust unit	% Variance [2]
Q1 2004 Cash flow from operations	**$ 108.0**	**$ 0.60**	**-**
Volume variance	(8.2)	(0.05)	(7)
Price variance	40.6	0.23	38
Change in cash losses on commodity and foreign currency contracts [1]	6.2	0.03	6
Royalties	(6.1)	(0.03)	(6)
Expenses:			
Transportation	0.2	-	-
Operating	3.1	0.02	3
Cash G&A	(1.3)	(0.01)	(1)
Interest	(0.5)	-	-
Capital taxes	(0.4)	-	-
Realized foreign exchange gain (loss)	(0.2)	-	-
Other	0.6	-	-
Weighted average trust units	-	(0.03)	-
Q1 2005 Cash flow from operations	**$ 142.0**	**$ 0.76**	**31**

(1) Represents cash losses on commodity and foreign currency contracts including cash settlements on termination of commodity and foreign currency contracts.
(2) Variance is calculated based on $ millions column.

Production

Production volumes averaged 55,410 boe/d in the first quarter of 2005 compared to 57,075 boe/d in the first quarter of 2004. The three per cent decrease in 2005 production compared to 2004 resulted primarily from the impact of non-core property dispositions of 1,800 boe/d in the second quarter of 2004. The incremental production from the Trust's capital development program in 2004 and the first quarter of 2005 served to offset the natural production declines on existing properties. The Trust's annual objective is to drill wells and incur other development expenditures in order to maintain production at current levels. In fulfilling this objective, there may be fluctuations in production depending on the timing of new wells coming on-stream.

	Three Months Ended March 31		
Production [1]	**2005**	2004	% Change
Crude oil (bbl/d)	**21,993**	23,663	(7)
Natural gas (mcf/d)	**176,073**	174,534	1
NGL (bbl/d)	**4,072**	4,323	(6)
Total production (boe/d)	**55,410**	**57,075**	**(3)**
% Natural las production	**53**	51	-
% Crude oil and liquids production	**47**	49	-

(1) Reported production for a period may include minor adjustments from previous production periods.

Oil production declined by seven per cent to 21,993 boe/d in the first quarter of 2005 from 23,663 boe/d in the first quarter of 2004. The decrease in oil production was largely attributed to the sale of the non-core assets in the second quarter of 2004 as the divested properties included approximately 1,100 boe/d of oil production. Natural production declines at existing properties also contributed to the reduction in oil production.

Natural gas production increased to 176.1 mmcf/d in the first quarter of 2005, a one per cent increase compared to first quarter 2004 natural gas production of 174.5 mmcf/d. The increase was due to production from the 96 shallow gas wells drilled in the southeast Alberta area in the second and third quarters of 2004 which contributed approximately 7.5 mmcf/d of new natural gas production late in 2004 and the Harrington and Bibler acquisition that closed on December 31, 2004. Property divestments in the second quarter of 2004 and natural production declines at existing properties partially offset the incremental production from the new shallow gas wells. The Trust's first quarter 2005 percentage natural gas production increased slightly to 53 per cent of production from 51 per cent in 2004 also as a result of the incremental gas production from the Trust's 2004 shallow gas drilling program.

During the first quarter of 2005, the Trust drilled 14 gross wells (13 net wells) on operated properties; 11 gross oil wells (11 net), two gross natural gas wells (two net) and one dry hole for a total success rate of 93 per cent in the first quarter of 2005. Of the wells drilled in the quarter, approximately eight wells were awaiting tie-in as of March 31, 2005 and are expected to be tied in during the second quarter of 2005.

The following table summarizes the Trust's production by core area for the first quarters of 2005 and 2004:

	Q1 2005				Q1 2004			
Core Areas [(1)]	**Total (boe/d)**	**Oil (bbls/d)**	**Gas (mmcf/d)**	**NGL (bbls/d)**	Total (boe/d)	Oil (bbls/d)	Gas (mmcf/d)	NGL (bbls/d)
Central AB	**8,505**	**1,511**	**31.2**	**1,800**	10,410	2,580	34.6	2,057
Northern AB & BC	**18,223**	**5,595**	**67.6**	**1,350**	18,414	5,682	68.0	1,406
Pembina	**7,188**	**3,575**	**17.1**	**767**	7,017	3,683	15.6	733
S.E. AB & S.W. Sask.	**11,262**	**1,513**	**58.4**	**18**	10,923	1,797	54.6	17
S.E. Sask.	**10,232**	**9,799**	**1.8**	**137**	10,311	9,921	1.7	110
Total	**55,410**	**21,993**	**176.1**	**4,072**	57,075	23,663	174.5	4,323

(1) Provincial references: AB is Alberta, BC is British Columbia, Sask. is Saskatchewan, S.E. is Southeast, S.W. is Southwest.

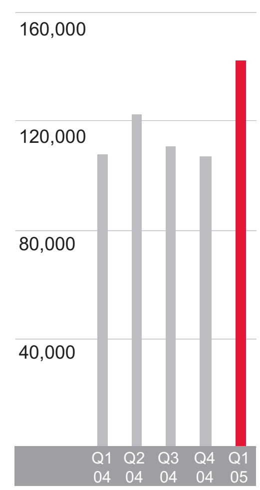
The Trust expects 2005 annual production to average approximately 54,800 boe/d. The 2005 production estimate incorporates incremental production from the planned $240 million capital program in 2005 in addition to 720 boe/d of incremental production from the Harrington & Bibler properties which were acquired on December 31, 2004 offset by natural declines at existing properties.

Commodity Prices Prior to Hedging

	Three Months Ended March 31		
Benchmark prices	**2005**	2004	% Change
AECO gas (CDN$/mcf) (1)	**6.69**	6.60	1
WTI oil (US$/bbl) (2)	**49.90**	35.16	42
USD/CAD foreign exchange rate	**0.82**	0.76	8
WTI oil (CDN$/bbl)	**61.21**	46.32	32

(1) Represents the AECO monthly posting.
(2) WTI represents West Texas Intermediate posting as denominated in US$.

CASH FLOW
(CDN$ millions)



The Canadian denominated oil price received by ARC and other Canadian energy companies was negatively impacted by the continued strength of the Canadian dollar with respect to the U.S. dollar during 2005. While crude oil prices reached a historic high of US$58.28 per barrel in the first quarter of 2005, the Canadian dollar also remained strong and closed the quarter at $0.83. Despite the 42 per cent increase in the US$ WTI oil price in the first quarter 2005, relative to 2004, the Canadian denominated oil price increased by only 32 per cent to $61.21 per barrel in the first quarter of 2005 compared to $46.32 per barrel in the first quarter of 2004. The Trust's realized oil price, before hedging, increased by 33 per cent to $53.63 per barrel in the first quarter of 2005 compared to $40.41 per barrel in 2004. The Trust's oil production consists predominantly of light and medium crude oil while heavy oil accounts for approximately five per cent of the Trust's liquids production.

The differential between the Edmonton posted price and field price widened in the fourth quarter of 2004 and continued at relatively wide levels throughout the first quarter of 2005, which reduced ARC's realized oil price. The quality and transportation differential on the Trust's oil production was approximately $7.98 in the first quarter of 2005 compared to $5.59 in the first quarter of 2004. The widening differential was mainly due to an increase in heavy and medium grade sour crude types entering the North American market, and a lack of incremental refining capacity to handle these grades of crude.

Alberta AECO monthly Hub prices averaged $6.69 per mcf in the first quarter of 2005 compared to $6.60 per mcf in the first quarter of 2004. ARC's realized gas price, before hedging, increased by eight per cent in the first quarter of 2005 to $7.20 per mcf compared to $6.64 per mcf in 2004. ARC's realized gas price is based on prices received at the various markets where the Trust sells its natural gas. ARC's natural gas sales portfolio consists of gas sales priced at the AECO monthly index, the AECO daily spot market, eastern and mid-west United States markets and a portion to aggregators.

Prior to hedging activities, ARC realized $47.74 per boe in the first quarter of 2005, a 21 per cent increase over the $39.58 per boe received prior to hedging in 2004.

The following is a summary of realized prices in the first quarters of 2005 and 2004 before hedging activities:

	Three Months Ended March 31		
ARC Realized Prices [(1)]	**2005**	2004	% Change
Oil ($/bbl)	**53.63**	40.41	33
Natural gas ($/mcf)	**7.20**	6.64	8
NGL's ($/bbl)	**46.57**	32.30	44
Total commodity revenue before hedging ($/boe)	**47.59**	39.52	20
Other revenue ($/boe)	**0.15**	0.06	150
Total revenue before hedging ($/boe)	**47.74**	39.58	21

(1) Prices as reported above are prior to gains and losses on commodity and foreign currency contracts and are prior to transportation charges. All gains and losses on commodity and foreign currency contracts are included in "loss on commodity and foreign currency contracts" in the statement of income.

Revenue

Revenue before hedging increased 16 per cent to $238.1 million in the first quarter of 2005 compared to the first quarter of 2004 revenue before hedging of $205.6 million. Significantly higher commodity prices contributed to higher revenue in the first quarter of 2005 relative to 2004.

A breakdown of revenue, before hedging activities, is as follows:

	Three Months Ended March 31		
Revenue ($ thousands) [(1)]	**2005**	2004	% Change
Oil revenue	**106,163**	87,025	22
Natural gas revenue	**114,093**	105,536	8
NGL's revenue	**17,063**	12,708	34
Total commodity revenue	**237,319**	205,269	16
Other revenue	**735**	325	126
Total revenue before hedging [(1)]	**238,054**	205,594	16

(1) Revenue as reported above is prior to gains and losses on commodity and foreign currency contracts and prior to transportation charges. All gains and losses on commodity and foreign currency contracts are included in "loss on commodity and foreign currency contracts" in the statement of income.

Risk Management and Hedging Activities

The Trust's hedging activities are conducted by an internal Risk Management Committee, based upon guidelines approved by the Board.

In response to the increased volatility characterized by current commodity markets, the Trust continues to execute a hedging strategy focused on price floor (put) structures to manage commodity prices and uses swaps to manage foreign exchange and interest rate exposures. The purchase of a price floor involves paying a premium to limit the exposure to downturns in commodity prices while participating in commodity price appreciation. The Trust considers these contracts to be effective economic hedges as they meet the objectives of the Trust's risk management mandate.

In order to mitigate credit risk, the Trust executes commodity and foreign currency hedging transactions with financially sound, credit worthy counterparties. All contracts require approval of the Trust's Risk Management Committee prior to execution.

ARC's current hedging portfolio for the remainder of 2005 and 2006 is as follows (see Note 5 in unaudited interim consolidated financial statements for additional information):

Oil and liquids contracts

Remaining 2005

- A total of 13,000 bbl/d hedged representing 49 per cent of estimated production.
  - 4,000 bbl/d swapped at a fixed price of US$28.95.
  - 500 bbl/d three-way collar in place with average price of US$34.00 x US$41.75 (US$30.00)
  - Remaining 8,500 bbl/d consists of bought puts, put spreads and short term layered three-way collars (average net premium cost is US$5.05 per bbl). The average price level protection of the floors on these contracts is US$46.07 with participation if prices increase above that level.
- The average hedge price, net of premiums, using the forward prices at March 31, 2005 is US$44.19/bbl.

Total 2006

- A total of 6,000 bbls/d hedged in the first quarter of 2006 and 4,000 boe/d hedged in the second quarter of 2006.
  - 2,000 bbls/d three-way collars in place with an average price of US$36.00 x US$40.33 (US$29.00) for the first half of 2006.
  - Remaining 2006 hedges of 4,000 bbls/d in the first quarter of 2006 and 2,000 bbls/d in the second quarter of 2006 are made up of bought puts and put spreads (average net premium cost is US$3.98 per bbl). The average price level protection of the floors on these contracts is US$50.00 with participation if prices increase above that level.
- The average hedge price, net of premiums, using the forward prices at March 31, 2005 is US$46.94/bbl.

Natural gas contracts

Remaining 2005

- A total of 89,256 GJ/d hedged representing 50 per cent of estimated production.
  - 15,563 GJ/d three-way collar in place with average price of CDN$6.25 x CDN$7.89 (CDN$5.25).
  - 31,984 GJ/d collar with an average price of CDN$6.58 x CDN$8.20.

- Remaining 41,709 GJ/d hedged is made up of bought puts, put spreads and some short term layered three-way collars (average net premium cost is CDN$0.63 per GJ). The average price level protection of the floors is CDN$6.90 with participation if prices increase above that level.

- The average hedge price, net of premiums, using the forward prices at March 31, 2005 is CDN$7.40/GJ.

Foreign exchange contracts

Remaining 2005

- Net US$137.1 million swapped at 1.2171 (0.8216).

Total 2006

- Net US$13 million swapped at 1.2058 (0.8293).

Interest rate contracts

- US$62.5 million 4.62 per cent fixed rate debt swapped to a floating rate of LIBOR + 38.25 bps.

Electricity contracts

- 5 MW/h swapped at a fixed price of $63.00 to 2010.

For the remainder of 2005, approximately 80 per cent of the oil (and liquids) and 73 per cent of the natural gas production will participate in the market price of the commodity with downside protection on approximately 49 per cent of the Trust's production, well above budgeted levels required to maintain distributions.

The Trust is committed to pay $28.3 million in option premiums on a portion of 2005 and 2006 hedged volumes. The premiums on the put contracts will be recorded as a realized cash hedging loss when payment is made in a future period. These premiums may be partially offset if ARC sells any short term options. The Trust's oil contracts are based on the WTI index and the majority of the Trust's natural gas contracts are based on the AECO monthly index.

The table below illustrates ARC's average hedged price, total corporate price in 2005 and commodity hedge gains and losses as a result of the Trust's 2005 commodity hedging program at various commodity prices. The foreign exchange table illustrates the gains and losses pursuant to the Trust's foreign exchange hedges at various CAD/USD exchange rates.

Impact of 2005 Hedging	Q2-Q4 2005 Commodity Price and Foreign Exchange Rate Assumptions			
Oil				
Oil Price per barrel (US$/WTI)	$ 30.00	$ 40.00	$ 50.00	$ 60.00
ARC's average hedged price (US$/barrel) (1)	37.24	37.75	40.02	46.19
Average price on forecasted volumes (US$/WTI) (1)	33.95	39.14	45.20	53.16
Oil hedging gains (losses) CDN$ millions (2) (3)	27.9	(11.9)	(43.9)	(59.1)
Natural Gas				
Gas Price per Gigajoule (CDN$/GJ)	$ 6.00	$ 7.00	$ 8.00	$ 9.00
ARC's average hedged price (CDN$/GJ)	6.12	6.54	7.36	7.70
Average price on forecasted volumes (CDN$/GJ)	6.16	6.77	7.62	7.89
Natural gas hedging gains (losses) CDN$ millions (3)	1.7	(11.6)	(13.4)	(26.9)
Foreign Exchange				
Foreign exchange rate (CAD/USD)	$ 1.28	$ 1.25	$ 1.22	$ 1.19
Foreign exchange rate (USD/CAD)	0.78	0.80	0.82	0.84
Foreign exchange hedge gains (losses) CDN$ millions(3)	(8.6)	(4.1)	(0.3)	2.7

(1) Incorporates the impact of hedging premiums.
(2) Based on foreign exchange rate assumption of USD/CAD$0.825.
(3) Intrinsic value.

Gain or Loss on Commodity and Foreign Currency Contracts

Gain or loss on commodity and foreign currency contracts comprise realized and unrealized gains or losses on commodity and foreign currency contracts that do not meet the requirements of an effective accounting hedge, even though the Trust considers all commodity and foreign currency contracts to be effective economic hedges. Accordingly, gains and losses on such contracts are shown as a separate expense in the statement of income.

The Trust recorded a loss on commodity and foreign currency contracts of $74 million in the first quarter of 2005, consisting of an unrealized fair value loss of $66.7 million and a realized cash loss of $7.3 million.

The following is a summary of the gain (loss) on commodity and foreign currency contracts for the first quarters of 2005 and 2004:

Commodity and foreign currency contracts ($ thousands)	**Crude Oil & Liquids**	**Natural Gas**	**Foreign Currency**	**Q1 2005 Total**	Q1 2004 Total
Realized cash (loss) gain on contracts [1]	**(13,544)**	**7,085**	**(855)**	**(7,314)**	(13,556)
Non-cash gain on contracts [2]	**-**	**-**	**-**	**-**	2,414
Non-cash amortization of opening deferred hedge (loss) gain [3]	**-**	**-**	**-**	**-**	(7,130)
Unrealized (loss) gain on contracts, change in fair value [4]	**(38,245)**	**(29,435)**	**993**	**(66,687)**	(16,475)
Total gain (loss) on commodity and foreign currency contracts	**(51,789)**	**(22,350)**	**138**	**(74,001)**	(34,747)

(1) Realized cash gains and losses represent actual cash settlements or receipts under the respective contracts.
(2) The non-cash gain of $2.4 million for 2004 represents non-cash amortization of deferred commodity and foreign currency contracts. The deferred commodity and foreign currency contracts were fully amortized at December 31, 2004.
(3) Represents non-cash amortization of the opening deferred hedge loss of $14.6 million to income over the terms of the contracts in place at January 1, 2004. The opening deferred hedge loss was fully amortized at December 31, 2004.
(4) The unrealized loss on contracts represents the change in fair value of the contracts during the period. The fair value of the contracts was a loss of $4 million at January 1, 2005 and a loss of $70.7 million at March 31, 2005.

The realized gain/(loss) on commodity and foreign currency contracts consists of gains/(losses) on fixed price transactions plus premiums paid on bought puts (net of premiums received on sold options). The unrealized gain/(loss) on commodity and foreign currency contracts reflects the change in the fair value of commodity and foreign exchange contracts and options during the reporting period. The market value of the bought puts may fluctuate but are limited to the actual premiums paid. The unrealized loss of $66.7 million in the first quarter was due to the significant increase in futures commodity pricing from January 1, 2005 to March 31, 2005 whereby the WTI price increased by 28 per cent and natural gas prices have increased by 24 per cent. The unrealized hedging losses are detailed below:

	Change in Value per Volume	Contracted Volume	Per cent of Production	Change in Mark to Market Value ($ millions)
Capped Contracts [1]				
2005 Oil	$ (11.69)	1,237,500 bbls	17%	$ (14.4)
2006 Oil	$ (14.57)	362,000 bbls	4%	$ (5.3)
2005 Gas	$ (0.97)	12,957,820 GJ	27%	$ (12.6)
Floor Contracts [2]				
2005 Oil	$ (7.62) [3]	2,337,500 bbls	32%	$ (17.8)
2006 Oil	$ (1.27)	542,000 bbls	6%	$ (0.7)
2005 Gas	$ (1.42)	11,887,794 GJ	24%	$ (16.9)
Foreign Exchange				
2005 Swaps	$ 0.0067	$ 137.1	20%	$ 0.9
2006 Swaps	$ 0.0056	$ 13	3%	$ 0.1
Total change in position				**$ (66.7)**

(1) Capped contracts contain a maximum price payable to the Trust and include swaps, collars and three-way contracts.
(2) Floor contracts are put contracts where the Trust has paid an amount for downside protection and retained 100 per cent of the upside.
(3) The change in the quarter included a reversal of a gain in the contract as at the end of the prior quarter, the original cost of the floor contracts was $5.22/bbl.

Operating Netbacks

The Trust's operating netback, after realized hedging losses, increased 34 per cent to $30.46 per boe in the first quarter of 2005 compared to $22.78 per boe in the first quarter of 2004. The increase in netbacks in 2005 is primarily due to higher realized commodity prices and lower operating costs.

The netbacks incorporate realized losses on commodity and foreign currency contracts of $1.47 per boe for the first quarter of 2005, compared to losses of $2.15 per boe in the first quarter of 2004. Unrealized fair value losses on commodity and foreign currency contracts of $66.7 million and $23.6 million in the first quarter of 2005 and 2004, respectively, were not recorded as a reduction of the netback.

The components of operating netbacks are shown below:

	Q1 2005				Q1 2004
Netback	Oil ($/bbl)	Gas ($/mcf)	NGL ($/bbl)	**Total ($/boe)**	Total ($/boe)
Weighted average sales price	53.63	7.20	46.57	**47.59**	39.52
Other revenue	-	-	-	**0.15**	0.06
Total revenue	53.63	7.20	46.57	**47.74**	39.58
Royalties	(9.61)	(1.34)	(12.56)	**(8.99)**	(7.46)
Transportation	(0.17)	(0.21)	-	**(0.72)**	(0.74)
Operating costs [1]	(9.19)	(0.64)	(5.69)	**(6.10)**	(6.45)
Netback prior to hedging	34.66	5.01	28.32	**31.93**	24.93
Realized gain (loss) on commodity and foreign currency contracts[2]	(7.27)	0.45	-	**(1.47)**	(2.15)
Netback after hedging	27.39	5.46	28.32	**30.46**	22.78

(1) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions have been made in allocating these costs between oil, natural gas and natural gas liquids production.

(2) Excludes unrealized fair value loss on commodity and foreign currency contracts of $66.7 million and $23.6 million in the first quarters of 2005 and 2004, respectively.

Royalties increased to $8.99 per boe in the first quarter of 2005 compared to $7.46 per boe in the first quarter of 2004. The increase in royalties per boe is the result of higher revenues in the first quarter of 2005 relative to 2004. Royalties as a percentage of pre-hedged commodity revenue net of transportation costs remained unchanged compared to the first quarter of 2004 at 19 per cent. Royalties are calculated and paid based on commodity revenue net of associated transportation costs and before any commodity hedging gains or losses.

A key objective of the Trust is to control costs, which was achieved in the quarter with operating costs, net of processing income, decreasing to $30.4 million in the first quarter of 2005 compared to $33.5 million in the same period of 2004. Operating costs per boe decreased five per cent to $6.10 per boe in 2005 compared to $6.45 per boe in the first quarter of 2004. Lower total and per boe operating costs in the first quarter of 2005 were primarily the result of the divestment of higher cost properties in the second quarter of 2004. The increased natural gas weighting of the Trust's 2005 first quarter production also served to reduce operating costs in total and per boe as natural gas production typically incurs a lower per boe operating cost than oil. The lower first quarter 2005 operating costs of $6.10 per boe are also indicative of the seasonality of field operations whereby the first and fourth quarters are typically the lowest cost periods for the Trust due to low levels of workover and maintenance activities. The Trust expects second and third quarter operating costs to increase as a result of planned workover and maintenance activities. The Trust received positive cost adjustments relating to prior production periods on certain non-operated properties in the first quarter that served to reduce the Trust's first quarter operating costs. The Trust's first quarter "run rate" more closely approximated $6.50 per boe.

The cost savings realized in late 2004 and the first quarter of 2005 from higher cost property divestitures and increased natural gas production were somewhat offset by the impact of higher costs of services throughout the industry, particularly for service rigs, trucking costs and mechanical services. The Trust expects the trend of increasing costs to continue in 2005 as the demand for services continues at unprecedented levels. Consequently, ARC expects 2005 average annual operating costs to increase slightly from 2004 levels to approximately $7.00 per boe.

Transportation costs decreased three per cent to $0.72 per boe in the first quarter of 2005 compared to $0.74 per boe in the first quarter of 2004. Transportation costs are defined by the point of legal transfer of the product and are dependent upon where the product is sold, product split, location of properties, and industry transportation rates. For the majority of ARC's gas production, legal title transfers at the intersection of major pipelines (referred to as "the Hub") whereas the majority of ARC's oil production is sold at the outlet to the field oil battery. Consequently, there are higher transportation costs incurred directly by ARC with gas production due to the distance from the wellhead to the Hub.

General and Administrative Expenses and Trust Unit Incentive Compensation

Cash general and administrative expenses ("G&A"), net of overhead recoveries on operated properties increased to $6.2 million ($1.24 per boe) in the first quarter of 2005 from $4.9 million ($0.94 per boe) in 2004. Increases in cash G&A expenses in total and per boe for 2005 were due to increased staff and compensation costs and a reduction in operating recoveries. As a result of the unprecedented levels of activity for ARC and for the industry as a whole, the costs associated with hiring, compensating and retaining employees and consultants have risen. Lower operating recoveries in the first quarter of 2005 also contributed to the increase in cash G&A. The reduction in operating recoveries was the result of lower average production and lower operating costs in the first quarter of 2005 relative to 2004.

The following is a breakdown of G&A and trust unit incentive compensation expense:

G&A and Trust Unit Incentive Compensation Expense ($ thousands except per boe)	Three Months Ended March 31 **2005**	2004	% Change
G&A expenses	**8,041**	7,401	9
Operating recoveries	**(1,875)**	(2,522)	(26)
Cash G&A expenses	**6,166**	4,879	26
Non-cash compensation - Rights Plan	**1,674**	2,845	(41)
Accrued cash compensation - Whole Unit Plan	**307**	-	-
Total G&A and trust unit incentive compensation expense	**8,147**	7,724	5
Cash G&A expenses per boe	**1.24**	0.94	32
Total G&A and trust unit incentive compensation expense per boe	**1.63**	1.49	9

A non-cash trust unit incentive compensation expense ("non-cash compensation expense") of $2 million ($0.39 per boe) was recorded in the first quarter of 2005 compared to $2.8 million ($0.55 per boe) in the first quarter of 2004. This non-cash amount relates to both the Trust Unit Incentive Rights Plan ("Rights Plan") and the Whole Trust Unit Incentive Plan ("Whole Unit Plan").

The $1.7 million non-cash expense for the Rights Plan in the first quarter of 2005 was determined based upon the fair value calculation. Only the rights that were issued on or after January 1, 2003 are subject to valuation and expense in the statement of income. Prior to the fourth quarter of 2004, the Trust recorded compensation expense for the rights based on an intrinsic value methodology that resulted in the expense amount being based on the underlying trust unit price at each period end and the exercise price of the rights. In the fourth quarter of 2004, the Trust adopted a fair value methodology of valuation of the rights based on certain assumptions and estimates. The Trust was able to determine fair value estimates given that the rights plan has now been discontinued, the remaining expected life of the rights is 1.1 years and there is more predictability regarding future distributions and the resulting future reductions in the rights exercise price.

As a result of the prospective application of this new standard in the fourth quarter of 2004, the first quarter 2005 rights expense is based on a fair value methodology while the rights expense for the first quarter of 2004 is based on an intrinsic value methodology. Consequently, there is no direct comparability of the rights expense for the two periods.

The Trust estimated the fair value of the rights issued in 2003 and 2004 based on the following assumptions and estimates:

Expected annual dividend	$1.80
Expected annual right's exercise price reduction	$0.72
Expected volatility	13.2%
Risk-free interest rate	3.7%
Expected life of rights (years)	1.1
Expected annual forfeitures (per cent)	-

The $0.3 million ($0.06 per boe) non-cash expense attributed to the new Whole Unit Plan is based on 342,652 committed trust units under the Whole Unit Plan as at March 31, 2005 (nil expense in the first quarter of 2004). The cumulative expense consists of a short-term portion of $1.4 million and a long-term portion of $1.8 million. Under the Whole Unit Plan, a non-cash expense is recorded each period in the statement of income. A realization of the expense and a resulting reduction in cash flow will occur each year when a cash payment is made upon vesting in the second quarter of each year. The first payment under the plan was made on April 30, 2005 in the amount of $1.4 million. This amount will be recorded as a reduction of cash flow in the second quarter of 2005.

The Trust expects 2005 G&A costs, excluding non-cash G&A associated with the Trust's Rights Plan and Whole Unit Plan, to be approximately $1.25 per boe. In addition, the Trust expects 2005 non-cash G&A of approximately $0.50 to $0.70 per boe for the non-cash trust unit incentive compensation expense associated with the Rights Plan and Whole Unit Plan.

It is the Trust's strategy to ensure compensation levels are competitive with industry peers and to ensure that ARC continues to attract and retain highly qualified individuals. As such, internal benchmarking show ARC's total G&A being in the mid-range compared to the Trust's peers in the conventional oil and gas sector.

Interest Expense

Interest expense increased to $3.1 million in the first quarter of 2005 from $2.6 million in the first quarter of 2004. The increase in interest expense is attributed to a higher average fixed-rate debt balance and slightly higher effective interest rate in the first quarter of 2005 relative to 2004. In the second quarter of 2004, the Trust issued $125 million of U.S. denominated fixed rate debt. With the issuance of the US$125 million of fixed rate debt, the Trust repaid all Canadian denominated revolving credit facilities, which were at a lower variable interest rate. The issuance of the fixed rate debt was undertaken in order to capitalize on low long-term interest rates in the United States. In addition, the holding of U.S. denominated debt results in a natural hedge as a rising Canadian dollar would result in a reduced Canadian payment to retire U.S. debt, which mitigates the impact of a rising Canadian dollar, which has an adverse effect on the Trust's Canadian denominated revenue due to commodity prices being referenced in U.S. dollars.

As at March 31, 2005, the Trust's debt balance was almost entirely U.S. denominated fixed rate debt with an average rate of 5.36 per cent (4.67 per cent including the current impact of the interest rate swap contracts) and an average remaining life of 6.3 years. With the issuance of the fixed rate notes and repayment of variable rate debt, the Trust's effective interest rate, before the impact of interest rate swaps, increased slightly.

Concurrent with the issuance of US$125 million of fixed rate debt, the Trust entered into interest rate swap agreements to convert US$62.5 million of fixed rate debt into floating rate debt at a rate equal to the three month LIBOR rate plus 38.25 basis points through to 2014. The Trust realized a cash gain of $0.3 million on the interest rate swap in the first quarter of 2005 (nil in the first quarter of 2004) and this amount has been netted against interest expense in the statement of income. The average interest rate on the interest rate swap was approximately 3.1 per cent during the first quarter of 2005.

The following is a summary of the debt balance and interest expense for the first quarters of 2005 and 2004:

Interest Expense ($ thousands)	Three Months Ended March 31 **2005**	 2004	 % Change
Period end debt balance (1)	**226,656**	245,796	(8)
Fixed rate debt	**221,357**	85,183	160
Floating rate debt	**5,299**	160,613	(97)
Interest expense before interest rate swaps (2)	**3,468**	2,618	32
Gain on interest rate hedge	**329**	-	-
Net interest expense	**3,139**	2,618	20

(1) Includes both long-term and current portions of debt.
(2) The interest rate swap was designated as an effective hedge for accounting purposes whereby actual realized gains and losses are netted against interest expense.

Foreign Exchange Gains and Losses

The Trust recorded a loss of $1 million ($0.21 per boe) on foreign exchange transactions in the first quarter of 2005 compared to a loss of $0.7 million ($0.13 per boe) in the first quarter of 2004. These amounts include both realized and unrealized foreign exchange gains and losses. Unrealized foreign exchange gains and losses are due to revaluation of U.S. denominated debt balances. The volatility of the Canadian dollar during the reporting period has a direct impact on the unrealized component of the foreign exchange gain or loss. The USD/CAD exchange rate was relatively stable during the first quarter of 2005. The unrealized gain/loss impacts net income but does not impact cash flow as it is a non-cash amount. Realized foreign exchange gains or losses arise from U.S. denominated transactions such as interest payments, debt repayments and hedging settlements.

The following is a breakdown of the total foreign exchange gain (loss) for the first quarter of 2005 and 2004:

Foreign Exchange Gain (Loss) ($ thousands except per boe)	Three Months Ended March 31 **2005**	 2004	 % Change
Unrealized (loss) on U.S. denominated debt	**(1,073)**	(943)	14
Realized gain on U.S. denominated transactions	**46**	243	(81)
Total Foreign exchange (loss)	**(1,027)**	(700)	47
Total Foreign exchange (loss) per boe	**(0.21)**	(0.13)	62

Taxes

Capital taxes paid or payable by ARC, based on debt and equity levels, remained unchanged at $0.7 million in the first quarter of 2005 compared to the same period of 2004.

In the first quarter of 2005, a future income tax recovery of $29.5 million was included in income compared to a $15.7 million recovery in the first quarter of 2004. The higher future income tax recovery in the first quarter of 2005 relative to 2004 was due to the higher unrealized loss on commodity and foreign currency contracts of $66.7 million in the first quarter of 2005 compared to $23.6 million in the first quarter of 2004. The total future income tax recovery of $29.5

million in the first quarter of 2005 included a recovery of $22.8 million for the unrealized hedge loss of $66.7 million. The first quarter 2004 future income tax recovery of $15.7 million included a recovery of $3.2 million due to the change in Alberta corporate income tax rates and a recovery of $8.2 million for the unrealized loss on commodity and foreign currency contracts.

ARC's expected future income tax rate is approximately 34 per cent compared to the current rate of approximately 38 per cent applicable to the 2005 income tax year.

On March 23, 2005, Saskatchewan Finance passed its 2005 budget which included an amendment to subject trusts to the Corporation Capital Tax Resource Surcharge ("resource surcharge") effective April 1, 2005. Previously, the resource surcharge did not apply to resource trusts and therefore the Trust was not impacted by the resource surcharge. However, due to the increase in the number of oil and gas producers that are now operating in Saskatchewan through a trust structure, the Saskatchewan government has now passed legislation to make the resource surcharge applicable to resource trusts effective April 1, 2005. The resource surcharge is calculated based on a rate applicable to working interest oil and natural gas revenue earned in Saskatchewan, with a rate of 3.6 per cent from wells drilled prior to October 1, 2002 and a rate of two per cent from wells drilled on or after October 1, 2002. Approximately 25 per cent of the Trust's current operations are in Saskatchewan. The Trust is currently assessing the future financial impact of the resource surcharge in light of the Trust's structure.

In the Trust's structure, payments are made between ARC Resources and the Trust, transferring both income and future tax liability to the unitholders. At the current time, ARC does not anticipate any cash income taxes will be paid by ARC Resources.

Depletion, Depreciation and Accretion of Asset Retirement Obligation

The depletion, depreciation and accretion ("DD&A") rate increased to $12.52 per boe in the first quarter of 2005 from $11.29 per boe in 2004. The higher DD&A rate is due to an increase in future development capital per the Trust's January 1, 2005 reserve evaluation compared to the January 1, 2004 reserve evaluation. Future development capital increased from $315.8 million to $374.2 million for proved reserves from January 1, 2004 to January 1, 2005. In addition, total proved reserves decreased by four per cent at January 1, 2005 compared to January 1, 2004 as a result of the non-core property divestment in the second quarter of 2004. In addition, the higher asset retirement obligation recorded in 2005 has resulted in higher accretion expense in 2005.

A breakdown of the DD&A rate is as follows:

DD&A Rate ($ thousands except per boe amounts)	Three Months Ended March 31 2005	 2004	 % Change
Depletion of oil & gas assets (1)	**61,215**	57,445	7
Accretion of asset retirement obligation (2)	**1,246**	1,167	7
Total DD&A	**62,461**	58,612	7
DD&A rate per boe	**12.52**	11.29	11

(1) Includes depletion of the capitalized portion of the asset retirement obligation that was capitalized to the property, plant and equipment ("PP&E") balance and is being depleted over the life of the reserves.

(2) Represents the accretion expense on the asset retirement obligation during the period.

The costs subject to depletion included $41.7 million relating to the capitalized portion of the asset retirement obligation as at March 31, 2005 ($41.1 million as at March 31, 2004), net of accumulated depletion.

Goodwill

The goodwill balance of $157.6 million arose as a result of the acquisition of Star in 2003. The goodwill balance was determined based on the excess of total consideration paid plus the future income tax liability less the fair value of the assets for accounting purposes acquired in the transaction.

Accounting standards require that the goodwill balance be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate that the balance might be impaired. If such an impairment exists, it would be charged to income in the period in which the impairment occurs. The Trust has determined that there was no goodwill impairment as of March 31, 2005.

Capital Expenditures and Net Acquisitions

Total capital expenditures, excluding acquisitions and dispositions, totaled $52.5 million in the first quarter of 2005 compared to $56.6 million in the first quarter of 2004. This amount was incurred on drilling and completions, geological, geophysical and facilities expenditures, as ARC continues to develop its asset base.

The Trust's strategy is to fully exploit its asset base and to increase the recoverable portion of total oil and natural gas reserves in place on land owned by the Trust.

In addition to the capital expenditures, the Trust completed minor net property acquisitions of $3.7 million, net of post closing adjustments, in the first quarter of 2005. The execution of minor property acquisitions and dispositions is part of the Trust's strategy to continually high-grade its asset base by acquiring additional interests in properties with future upside potential and disposing of properties with limited upside potential.

A breakdown of capital expenditures and net acquisitions is shown below:

	Three Months Ended March 31		
Capital Expenditures ($ thousands)	**2005**	2004	% Change
Geological and geophysical	**1,262**	2,320	(46)
Drilling and completions	**36,042**	37,942	(5)
Plant and facilities	**14,495**	15,956	(9)
Other capital	**721**	341	111
Total capital expenditures	**52,520**	56,559	(7)
Producing property acquisitions [(1)]	**3,844**	1,679	129
Producing property dispositions [(1)]	**(176)**	(105)	68
Total capital expenditures and net acquisitions	**56,188**	58,133	(3)
Capital expenditures and net acquisitions financed with cash flow	**52,520**	25,124	109
Capital expenditures and net acquisitions financed with debt and equity	**3,668**	33,009	(89)

(1) Value is net of post-closing adjustments.

ARC expects to undertake significant development projects in 2005 to fully execute the capital program of approximately $240 million.

Asset Retirement Obligation and Reclamation Fund

At March 31, 2005, the Trust has recorded an Asset Retirement Obligation (“ARO”) of $73.2 million ($66.9 million at March 31, 2004) for future abandonment and reclamation of the Trust’s properties. The ARO increased by $1.2 million for accretion expense and was reduced by $1 million for actual abandonment expenditures incurred in the first quarter of 2005. The Trust did not record a gain or loss on actual abandonment expenditures incurred in 2005 as the costs closely approximated the liability value included in the ARO.

ARC contributed $1.5 million cash to its reclamation fund in the first quarter of 2005 ($1.5 million in the first quarter of 2004) and earned interest of $0.2 million ($0.2 million in 2004) on the fund balance. The fund balance was reduced by $1.1 million for cash-funded abandonment expenditures in the first quarter of 2005 (nil in the first quarter of 2004). This fund, invested in money market instruments, is established to provide for future abandonment and reclamation liabilities. Future contributions are currently set at approximately $6 million per year over 20 years in order to provide for the total estimated future abandonment and reclamation costs that are to be incurred over the next 61 years. The annual funding of the reclamation fund results in all unitholders over time sharing in the cost of the eventual abandonment of the Trust’s properties.

A breakdown of the Trust's capital structure is as follows:

Capitalization, Financial Resources and Liquidity ($ thousands except per unit and per cent amounts)	**March 31, 2005**	December 31, 2004
Long-term debt	**218,189**	211,834
Short-term debt	**8,467**	8,715
Working capital deficit excluding short-term debt (1)	**27,596**	44,293
Net debt obligations	**254,252**	264,842
Units outstanding and issuable for exchangeable shares (thousands)	**189,609**	188,804
Market price per unit at end of period	**18.15**	17.90
Market value of trust units and exchangeable shares	**3,441,403**	3,379,592
Total capitalization (2)	**3,695,655**	3,644,434
Net debt as a percentage of total capitalization	**6.9%**	7.3%
Net debt obligations	**254,252**	264,842
Cash flow from operations	**141,965**	448,033
Net debt to annualized cash flow	**0.4**	0.6

(1) The 2005 and 2004 working capital deficit excludes the net current liability of $70.7 million and $4 million, respectively, for the fair value of commodity and foreign currency contracts.

(2) Total capitalization as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received by the Trust.

The Trust's credit facilities are consolidated into one syndicated credit facility with a total borrowing base of $620 million. The Trust recently completed the annual credit review which resulted in the borrowing base and terms of the credit facility remaining unchanged. ARC Resources' and ARC (Sask) Trust's oil and gas properties continue to secure the debt.

As at March 31, 2005 net debt to total capitalization was 6.9 per cent and net debt to annualized first quarter 2005 cash flow was approximately 0.4 times (0.6 times at December 31, 2004), well within the Trust's objective of net debt at or below the 1.0 times cash flow during high commodity price environments.

The Trust funded 100 per cent of its first quarter capital development program of $52.5 million with cash flow. The Trust intends to finance the majority of the remaining $188.5 million portion of the $240 million 2005 capital development program with cash flow and proceeds from the distribution reinvestment program with the remainder financed with debt.

Unitholders' Equity

At March 31, 2005, there were 189.6 million trust units issued and issuable for exchangeable shares, a slight increase from the 188.8 million trust units issued and issuable for exchangeable shares at December 31, 2004. The increase in the number of trust units outstanding is attributable to 0.5 million trust units issued pursuant to the Distribution Reinvestment Incentive Plan ("DRIP") at an average price of $17.81 per trust unit, 0.2 million trust units issued pursuant to the exercise of employee rights at an average price of $12.07 per trust unit, and 0.1 million trust units issued upon conversion of exchangeable shares.

The existing rights plan will be in place until the remaining 2.7 million rights outstanding as of March 31, 2005 are exercised or cancelled as no additional rights will be issued under the plan due to discontinuation of the plan in the second quarter of 2004. The holder has the option to exercise the rights at the original grant price or a price which is adjusted downward over time by the amount, if any, of the annual distributions that exceed 10 per cent of the net book value of the property, plant and equipment. The rights have a five-year term and vest equally over three years from the date of grant. Rights to purchase 2.7 million trust units at an average adjusted exercise price of $10.75 were outstanding at March 31, 2005. While these rights have an average remaining contractual life of 3.1 years and expire at various dates to March 22, 2009, a total of 0.6 million rights were exercisable at March 31, 2005 and an additional 1.3 million rights become exercisable on May 6, 2005.

The Whole Unit Plan results in the issuance of a certain number of underlying trust units to employees, officers and directors of the Trust. The underlying trust units take the form of Restricted Trust Units “RTU’s” which vest equally over three years or Performance Trust Units “PTU’s” which vest in total at the end of three years. Upon vesting, the individual receives a cash payment equal to the current value of the underlying trust units including accrued distributions. Consequently, the Whole Unit Plan is a cash plan whereby there will be no trust units being issued from treasury under the plan. At March 31, 2005 there were 342,652 RTU’s and PTU’s outstanding under the Whole Unit Plan of which 72,932 RTU’s vested on April 15, 2005 and resulted in a cash payment of $1.4 million, including accrued distributions, to the holders of the RTU’s. Each year, additional RTU’s and PTU’s will be issued to employees, officers and directors of the Trust. The Trust has made provisions whereby employees may elect to have trust units purchased for them on the market with the cash received upon vesting.

Unitholders electing to reinvest distributions or make optional cash payments to acquire trust units from treasury under the DRIP may do so at a five per cent discount to the prevailing market price with no additional fees or commissions.

Non-Controlling Interest

The Trust has recorded non-controlling interest attributed to the issued and outstanding exchangeable shares of ARC Resources Ltd. (“ARL”), a corporate subsidiary of the Trust, in accordance with new accounting requirements pursuant to EIC-151 (see “Impact of New Accounting Policies” section of this MD&A for further discussion). The intent of the new standard is that exchangeable shares of a subsidiary which are transferable to third parties, outside of the consolidated entity, represent a non-controlling interest in the subsidiary.

The exchangeable shares of ARL are publicly traded and therefore are transferable to third parties within a period of time. The exchangeable shares rank equally with the trust units and the two are considered to be economically equivalent. There are no provisions whereby the exchangeable shareholders have certain rights or terms which are not eligible to the Trust unitholders. Therefore, the Trust does not believe that there is a permanent non-controlling interest as all exchangeable shares will ultimately be converted to trust units either by means of redemption by the exchangeable shareholders or by passage of time whereby ARL will redeem the exchangeable shares for trust units. Consequently, as the exchangeable shares are redeemed for trust units over time, the non-controlling interest will decrease and eventually will be nil when all exchangeable shares have been converted to trust units on or before

August 29, 2012. However, the Trust has reflected the non-controlling interest in accordance with the requirements of EIC-151.

The non-controlling interest of $35.8 million at March 31, 2005 ($36 million at December 31, 2004) on the consolidated balance sheet represents the book value of exchangeable shares plus accumulated earnings attributable to the outstanding exchangeable shares. The reduction in first quarter 2005 and 2004 net income, respectively, of $0.6 million and $0.7 million, represents the net income attributable to the exchangeable shareholders for the first quarters of 2005 and 2004, respectively. As the exchangeable shares are converted to trust units, Unitholders' capital is increased for the book value of the trust units issued.

As at March 31, 2005 there were 1.7 million exchangeable shares of ARL outstanding at an exchange ratio of 1.71265 whereby three million trust units would be issuable upon conversion. The exchangeable shares can be converted into trust units or redeemed by the exchangeable shareholder for trust units at any time. ARL may redeem all outstanding exchangeable shares on or before August 29, 2012 and may redeem the exchangeable shares at any time if the number of exchangeable shares outstanding falls below 100,000 shares. ARL may issue cash or trust units upon redemption of exchangeable shares and it is the intention to issue trust units upon redemption.

The new standard has been applied retroactively with restatement of prior periods. Consequently, previously reported first quarter 2004 net income has been restated to reflect the impact of the new standard. See "Impact of New Accounting Policies" in this MD&A for a quantification of the impact of this standard.

Cash Distributions

ARC declared cash distributions of $83.9 million ($0.45 per unit), representing 59 per cent of first quarter 2005 cash flow compared to cash distributions of $81.2 million ($0.45 per unit), representing 75 per cent of cash flow in the first quarter of 2004. The remaining 41 per cent of first quarter 2005 cash flow ($58.1 million) was used to fund 100 per cent of ARC's first quarter 2005 capital expenditures ($52.5 million), make contributions, including interest, to the reclamation fund ($1.7 million) and to apply $3.9 million to working capital. The actual amount of cash flow withheld to fund the Trust's capital expenditure program is dependent on the commodity price environment and is at the discretion of the Board of Directors.

Cash flow and cash distributions in total and per unit for the first quarters of 2005 and 2004 were as follows:

	Three Months Ended March 31		%	Three Months Ended March 31		%
Cash flow and distributions	**2005**	2004	Change	**2005**	2004	Change
	($ millions)			($ per unit)		
Cash flow from operations	**142.0**	108.0	31	**0.76**	0.59	29
Reclamation fund contributions (1)	**(1.7)**	(1.7)	-	**(0.01)**	(0.01)	-
Capital expenditures funded with cash flow	**(52.5)**	(25.1)	109	**(0.28)**	(0.14)	100
Discretionary debt repayments	**(3.9)**	-	-	**-**	-	-
Other (2)	**-**	-		**(0.02)**	0.01	100
Cash distributions	**83.9**	81.2	3	**0.45**	0.45	-

(1) Includes interest income earned on the reclamation fund balance that is retained in the reclamation fund.
(2) Other represents the difference due to cash distributions paid being based on actual units at each distribution date whereas per unit cash flow, reclamation fund contributions and capital expenditures funded with cash flow are based on weighted average trust units in the year.

Monthly cash distributions for the first quarter of 2005 have been set at $0.15 per trust unit subject to monthly review based on commodity price fluctuations. Revisions, if any, to the monthly distribution are normally announced on a quarterly basis in the context of prevailing and anticipated commodity prices at that time.

Historical Cash Distributions by Calendar Year

The following table presents cash distributions paid in each calendar period. Cash distributions for 2005 include distributions paid up to and including April 15, 2005:

Calendar Year	Distributions (1)	Taxable Portion	Return of Capital
2005 YTD (2)	0.60 (2)	0.57 (2)	0.03 (2)
2004	1.80	1.69	0.11
2003	1.78	1.51	0.27
2002	1.58	1.07	0.51
2001	2.41	1.64	0.77
2000	1.86	0.84	1.02
1999	1.25	0.26	0.99
1998	1.20	0.12	1.08
1997	1.40	0.31	1.09
1996	0.81	-	0.81
Cumulative	**$14.69**	**$8.01**	**$6.68**

(1) Based on cash distributions paid in the calendar year.
(2) Based on cash distributions paid in 2005 up to and including April 15, 2005 and estimated taxable portion of 2005 distributions of 95 per cent.

__2005 Monthly Cash Distributions__

Actual cash distributions paid for 2005 along with relevant payment dates are as follows:

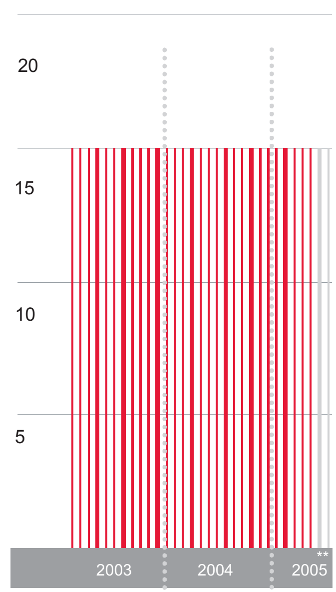
Ex-Distribution Date	Record Date	Distribution Payment Date	Total Distribution
December 29, 2004	December 31, 2004	January 15, 2005	0.15
January 27, 2005	January 31, 2005	February 15, 2005	0.15
February 24, 2005	February 28, 2005	March 15, 2005	0.15
March 29, 2005	March 31, 2005	April 15, 2005	0.15
April 27, 2005	April 30, 2005	May 16, 2005	0.15
May 27, 2005	May 31, 2005	June 15, 2005	0.15*
June 28, 2005	June 30, 2005	July 15, 2005	0.15*
July 27, 2005	July 31, 2005	August 15, 2005	
August 28, 2005	August 31, 2005	September 15, 2005	
September 28, 2005	September 30, 2005	October 17, 2005	
October 27, 2005	October 31, 2005	November 15, 2005	
November 28, 2005	November 30, 2005	December 15, 2005	

* Estimated

__Taxation of Cash Distributions__

Cash distributions comprise a return of capital portion (tax deferred) and a return on capital portion (taxable). The return of capital component reduces the cost basis of the trust units held. For a more detailed breakdown, please visit our website at www.arcenergytrust.com.

MONTHLY CASH DISTRIBUTIONS
(CAD cents/trust unit)



* Estimate based on current market outlook and subject to change based on actual market conditions

For 2005, it is estimated that cash distributions paid in the calendar year will be 95 per cent return on capital (taxable) and five per cent return of capital (tax deferred). The increase in the taxable portion of distributions to 95 per cent is the result of increasing commodity prices and in turn increasing cash flow of the Trust. Actual taxable amounts may differ from the estimated amount as they are dependent on commodity prices experienced throughout the year. Changes in the estimated taxable and deferred portion of the distributions will be announced quarterly.

The exchangeable shares of ARL may provide a more tax-effective basis for investment in the Trust. The ARL exchangeable shares are traded on the TSX under the symbol "ARX" and are convertible into trust units, at the option of the shareholder, based on the then current exchange ratio. Exchangeable shareholders are not eligible to receive monthly cash distributions, however the exchange ratio increases on a monthly basis by an amount equal to the current month's trust unit distribution multiplied by the then current exchange ratio and divided by the 10 day weighted average trading price of the trust units at the end of each month. The gain realized as a result of the monthly increase in the exchange ratio is taxed, in most circumstances, as a capital gain rather than income and is therefore subject to a lower effective tax rate. Tax on the exchangeable shares is deferred until the exchangeable share is sold or converted into a trust unit.

Contractual Obligations and Commitments

The Trust has contractual obligations in the normal course of operations including purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, and lease rental obligations. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. The Trust also has contractual obligations and commitments that are of a less routine nature and which are disclosed in Note 13 of the unaudited interim consolidated financial statements.

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that the Trust has committed to approximately $40 to $60 million of capital expenditures by means of giving the necessary authorizations to incur the capital in a future period. This commitment has not been disclosed in the commitment table in Note 13 of the unaudited interim consolidated financial statements as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that pending litigation will not have a material adverse impact on the Trust's financial position or results of operations.

Off Balance Sheet Arrangements

The Trust has certain lease agreements that are entered into in the normal course of operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as of March 31, 2005. The total obligation for future lease payments under all operating leases is disclosed in Note 13 of the unaudited interim consolidated financial statements.

The Trust entered into agreements to pay premiums pursuant to certain crude oil derivative put contracts. Premiums of approximately $28.3 million will be paid in 2005 and 2006 for the put contracts in place at March 31, 2005. As the premiums are part of the underlying derivative contract, they have been recorded at fair market value at March 31, 2005 on the balance sheet. The total obligation for future premium payments is disclosed in the Note 13 of the unaudited interim consolidated financial statements.

Impact of New Accounting Policies

In 2004, the Trust implemented the following new accounting policies and instruments pursuant to requirements of the Canadian Institute of Chartered Accountants ("CICA"). The implementation of these new policies impacted the financial results for 2005 and comparative periods of 2004 as follows:

Non-Controlling Interest - On January 19, 2005 the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states that exchangeable securities issued by a subsidiary of an income trust certain criteria. The exchangeable shares issued by ARC Resources Ltd. ("ARL"), a wholly owned corporate subsidiary of the Trust, are publicly traded and therefore are considered, by EIC-151, to be transferable to third parties. EIC-151 states that if the exchangeable shares are "transferable" to a third party, they should be reflected as non-controlling interest. Previously, the exchangeable shares were reflected as a component of Unitholders' Equity. Accordingly, the Trust has reflected non-controlling interest of $35.8 million and $36 million, respectively, on the Trust's consolidated balance sheet as at March 31, 2005 and December 31, 2004. Consolidated net income has been reduced for net income attributable to the non-controlling interest of $0.6 million and $0.7 million, respectively, in the first quarter of 2005 and 2004. In accordance with the transitional provisions of EIC-151, retroactive application has been applied with restatement of prior periods. As a result of retroactive restatement, previously reported net income for the first quarter of 2004 has been reduced by $0.7 million to $39.5 million for the net income attributable to the non-controlling interest. In addition, previously reported cash flow per unit and net income per unit have been restated to reflect the weighted average trust units excluding trust units issuable for exchangeable shares.

Financial Reporting Update

In addition to the above policies implemented in 2004, the following new and amended standards have been reviewed by the Trust:

Variable Interest Entities —In June 2003, the CICA issued Accounting Guideline 15 "Consolidation of Variable Interest Entities" that deals with the consolidation of entities which are subject to control on a basis other than ownership of voting interests. This new guideline is effective for fiscal years beginning on or after November 1, 2004. The Trust has assessed that this guideline has no current impact based on the current structure. The Trust will consider the applicability of this guideline in the future and assess the appropriate financial statement implications at that time.

Redeemable or Retractable Shares — On November 5, 2004, the CICA issued EIC-149 "Accounting for Retractable or Mandatorily Redeemable Shares" that lists specific criteria required to be met in order for entities to reflect trust units and exchangeable shares as either a liability or equity in their financial statements. The trust units and exchangeable shares meet the required criteria to be reflected as Unitholders' Equity and no additional presentation or disclosure is required.

Financial Instruments —Recognition and Measurement —On January 27, 2005 the Accounting Standard's Board (AcSB) issued CICA Handbook section 3855 "Financial Instruments —Recognition and Measurement", CICA Handbook section 1530 "Comprehensive Income" and CICA Handbook section 3865 "Hedges" that deal with the recognition and measurement of financial instruments and comprehensive income. The new standards are intended to harmonize Canadian standards with United States and International accounting standards and are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. These new standards will impact the Trust in future periods and the resulting impact will be assessed at that time.

Critical Accounting Estimates

The Trust has continuously evolved and documented its management and internal reporting systems to provide assurance that accurate, timely internal and external information is gathered and disseminated.

The Trust's financial and operating results incorporate certain estimates including:

a) estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
b) estimated capital expenditures on projects that are in progress;
c) estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves which the Trust expects to recover in the future;
d) estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;
e) estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures; and
f) estimated future recoverable value of property, plant and equipment and goodwill.

The Trust has hired individuals and consultants who have the skill set to make such estimates and ensures individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

The ARC Leadership team's mandate includes ongoing development of procedures, standards and systems to allow ARC staff to make the best decisions possible and ensuring those decisions are in compliance with the Trust's environmental, health and safety policies.

Sarbanes Oxley Update

On July 31, 2002, the United States Congress enacted the Sarbanes Oxley Act ("SOX") which applies to all companies registered with the Securities and Exchange Commission ("SEC"). On March 2, 2005, the Securities and Exchange Commission ("SEC") announced a one year extension of the compliance date for all foreign private issuers. As a result of this extension, ARC is currently required to comply with section 404 of the SOX legislation on December 31, 2006. Section 404 of the SOX legislation "Internal Controls Over Financial Reporting" requires that management identify, document, assess, and remediate internal controls and issue an opinion on the effectiveness of internal controls surrounding the financial reporting process. The Trust currently has a comprehensive plan and a dedicated team of individuals in place to execute the plan of meeting the SOX Section 404 compliance date.

Objectives and 2005 Outlook

It is the Trust's objective to provide the highest possible long-term returns to unitholders by focusing on the key strategic objectives of the business plan.

To the end of the first quarter of 2005, the Trust has provided cumulative cash distributions of $14.69 per trust unit and capital appreciation of $8.15 per trust unit for a total return of $22.84 per trust unit (24.1 per cent annualized total return) for unitholders who invested in the Trust at inception. During the first quarter of 2005, the Trust provided unitholders with an annualized total return of 16.1 per cent.

During 2005, ARC will continue to be active with a robust drilling and development program on its diverse asset base. The $240 million capital expenditure budget for 2005 is the largest in the Trust's history excluding acquisitions. The Trust will prudently deploy capital with a balanced drilling program of low and moderate risk wells. The 2004 drilling program resulted in a 99 per cent success rate and the Trust strives for the same success rate in 2005. The Trust continues to focus on major properties with significant upside, with the objective to replace production declines through internal development opportunities.

The low debt levels and strong working capital position provide the Trust with the financial flexibility to fund the 2005 capital expenditure program and be poised to take advantage of accretive acquisition opportunities. The Trust continually reviews potential acquisitions of both conventional oil and natural gas reserves and in the broader energy industry. Acquisitions are evaluated internally and acquisitions in excess of $10 million are subject to Board approval.

Following is a summary of the Trust's 2005 Guidance issued by way of press release on January 3, 2005 compared to reported actual results for the first quarter of 2005:

	2005 Annual Guidance	**2005 Actual Q1**	**% Variance**
Production (boe/d)	54,800	55,410	1
Expenses ($/boe):			
Operating costs	7.00	6.10	(13)
Transportation	0.70	0.72	3
G&A expenses —cash	1.25	1.24	(1)
G&A expenses —stock compensation plans	0.30	0.39	30
Interest	0.75	0.63	(16)
Cash taxes	0.15	0.13	(13)
Capital expenditures ($ millions)	240	53	-
Weighted average trust units (millions)	191.0	186.2	-

The Trust expects to complete the year 2005 in accordance with Guidance targets released in January 2005. To the end of the first quarter of 2005 there were some variances between annual guidance and actuals to the end of the first quarter, however actuals are expected to converge with guidance targets as the year progresses with exceptions noted below.

The variance-to-date for operating costs is attributed to the seasonality of operating costs whereby the first quarter is typically the lowest cost quarter of the year. As workover and maintenance activities are undertaken in the second and third quarters, the Trust expects that actual operating costs will more closely approximate the guidance of $7.00 per boe for the year 2005.

Non-cash G&A was above guidance in the first quarter of 2005 as a result of the historic high trust unit price in the first quarter. The Trust expects non-cash G&A to be higher than the original annual guidance of $0.30 per boe as a result of the continued strength in the trust unit price which drives the value of non-cash compensation. The Trust currently estimates the 2005 annual non-cash G&A to approximate $0.50 to $0.70 per boe for the full year. As this is a non-cash amount, there is no impact on 2005 cash flow as a result of the revised guidance estimate.

Interest expense in the first quarter of 2005 was lower than the guidance target for 2005 as a result of record level of cash flow in the quarter, which resulted in the Trust funding 100 per cent of its capital program with cash rather than debt. Consequently, debt levels and the corresponding interest expense were lower than anticipated during the first quarter of 2005. However, the Trust still expects interest to closely approximate the annual guidance of $0.75 per boe for the full year.

Cash taxes per boe of $0.13 for the first quarter of 2005 were below the guidance level of $0.15 as a result of higher average production in the first quarter compared to the annual average guidance. The Trust expects that cash taxes will closely approximate the original guidance of $0.15 per boe for the year. With the legislation of the Saskatchewan Corporation Capital Tax Resource Surcharge in February 2005, the Trust estimates that cash flow will be reduced by $2 million per quarter commencing in the second quarter of 2005. However, due to the production based nature of the resource surcharge, the additional expense will be reflected as a royalty expense rather than a tax expense in the statement of income. Accordingly, the resource surcharge is not expected to impact the guidance of $0.15 per boe for annual cash taxes in 2005.

To the end of the first quarter, the Trust had incurred $52.5 million of capital expenditures pursuant to the $240 million 2005 capital development program. The Trust has significant capital development projects planned for the remainder of 2005 whereby the Trust expects to meet the annual 2005 capital expenditure guidance target of $240 million by the end of 2005.

See “Outlook” in the Trust’s Annual Report MD&A for additional discussion of the Trust’s key future objectives.

2005 Cash Flow

Below is a table that illustrates sensitivities to pre-hedged cash flow with operational changes and changes to the business environment:

			Impact on Annual Cash Flow		Impact on Annual Distributions [2]
Business environment	**Assumption**	**Change**	**$/Unit**	**%**	**$/Unit**
Oil price (US$WTI/barrel) [1]	$ 50.00	$ 1.00	$ 0.05	1.7%	$ 0.04
Natural gas price (CDN$AECO/mcf) [1]	$ 7.00	$ 0.10	$ 0.03	1.0%	$ 0.02
USD/CAD exchange rate	$ 0.82	$ 0.01	$ 0.04	1.8%	$ 0.04
Interest rate on debt	5.1%	1.0%	$ 0.01	0.5%	$ 0.01
Operational					
Liquids production volume (bbls/d)	26,500	1.0%	$ 0.02	0.6%	$ 0.01
Gas production volumes (Mmcf/d)	170.0	1.0%	$ 0.02	0.6%	$ 0.01
Operating expenses per boe	$ 7.00	1.0%	$ 0.01	0.3%	$ 0.01
Cash G&A expenses per boe	$ 1.25	10.0%	$ 0.02	0.6%	$ 0.01

(1) Analysis does not include the effect of hedging.
(2) Analysis assumes a 20 per cent holdback on distributions.

Assessment of Business Risks

The ARC management team is focused on long-term strategic planning and has identified the key risks, uncertainties and opportunities associated with the Trust's business that can impact the financial results. See "Assessment of Business Risks" in the Trust's 2004 Annual Report MD&A for a detailed assessment.

Additional Information

Additional information relating to ARC can be found on SEDAR at www.sedar.com.

QUARTERLY REVIEW

(CDN$ thousands, except per unit amounts)	2005	2004				2003		
FINANCIAL	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenue before royalties	**238,054**	232,112	230,769	233,307	205,594	182,558	184,166	198,542
Per unit [1]	**1.28**	1.25	1.25	1.28	1.14	1.06	1.13	1.39
Cash flow	**141,965**	106,935	110,835	122,249	108,014	89,617	87,511	116,546
Per unit —basic [1]	**0.76**	0.58	0.60	0.67	0.60	0.52	0.54	0.82
Per unit —diluted	**0.74**	0.56	0.59	0.65	0.58	0.51	0.52	0.72
Net income [5]	**38,646**	112,995	38,897	50,338	39,460	53,492	40,785	125,740
Per unit —basic [5] [6]	**0.21**	0.61	0.21	0.28	0.22	0.31	0.25	0.88
Per unit —diluted	**0.20**	0.60	0.21	0.27	0.22	0.31	0.25	0.79
Cash distributions	**83,867**	83,531	83,178	82,053	81,215	78,603	73,890	67,495
Per unit [2]	**0.45**	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Total assets [8]	**2,303,948**	2,304,998	2,316,297	2,309,599	2,278,608	2,281,775	2,251,273	2,332,734
Total liabilities [8]	**785,776**	755,650	804,603	768,073	752,166	730,039	886,887	941,215
Net debt outstanding [4]	**254,252**	264,842	220,500	220,074	284,001	262,071	412,686	466,988
Weighted average units (thousands) [3]	**186,224**	185,539	184,675	181,948	180,283	171,993	163,334	145,526
Units outstanding and issuable at period end (thousands) [3]	**189,609**	188,804	188,185	187,296	183,980	182,777	167,531	163,184
CAPITAL EXPENDITURES ($ thousands)								
Geological and geophysical	**1,262**	867	828	1,373	2,320	2,846	1,171	656
Drilling and completions	**36,042**	39,125	42,553	24,867	37,942	37,738	31,661	23,834
Plant and facilities	**14,495**	6,183	11,668	7,282	15,956	15,512	11,917	4,831
Other capital	**721**	1,480	394	605	341	1,418	391	1,325
Total capital expenditures	**52,520**	47,655	55,443	34,127	56,559	57,515	45,140	30,646
Property acquisitions (dispositions) net	**3,668**	(1,036)	(5,345)	(53,412)	1,574	(3,693)	(81,166)	(79,750)
Corporate acquisitions [7]	**-**	41,449	-	30,560	-	-	258	721,332
Total capital expenditures and net acquisitions	**56,188**	88,068	50,098	11,275	58,133	53,822	(35,768)	672,228
OPERATING								
Production								
Crude oil (bbl/d)	**21,993**	22,969	22,496	22,720	23,663	22,851	23,522	24,078
Natural gas (Mmcf/d)	**176,073**	174.7	177.4	186.7	174.5	180.8	182.0	175.7
Natural gas liquids (bbl/d)	**4,072**	4,097	4,034	4,313	4,323	4,140	4,105	4,397
Total (boe/d 6:1)	**55,410**	56,179	56,096	58,147	57,075	57,120	57,968	57,759
Average prices								
Crude oil ($/bbl)	**53.63**	49.48	51.00	47.43	40.41	35.21	35.33	36.61
Natural gas ($/mcf)	**7.20**	6.82	6.65	6.99	6.64	5.85	5.64	6.59
Natural gas liquids ($/bbl)	**46.57**	43.72	42.30	38.22	32.30	30.14	30.92	28.83
Oil equivalent ($/boe) [9]	**47.74**	44.91	44.72	44.09	39.58	34.78	34.53	37.77
TRUST UNIT TRADING (based on intra-day trading)								
Unit prices								
High	**20.40**	17.98	17.38	15.74	15.74	14.87	13.88	12.84
Low	**16.55**	14.80	15.02	14.28	13.50	13.31	12.51	11.29
Close	**18.15**	17.90	16.85	15.35	15.64	14.74	13.55	12.50
Average daily volume (thousands)	**895**	456	384	337	502	395	551	503

(1) Based on weighted average trust units.
(2) Based on number of trust units outstanding at each cash distribution date.
(3) Excludes trust units issuable for outstanding exchangeable shares.
(4) Total current and long-term debt net of working capital. Net debt excludes commodity and foreign currency contracts, the deferred hedge loss and deferred commodity and foreign currency contracts.
(5) Net income and net income per unit have been restated due to the retroactive application of the change in accounting policies relating to non-controlling interest that was implemented in 2004.
(6) Net income in the basic per trust unit calculation has been reduced by interest in the convertible debentures.
(7) Represents total consideration for the corporate acquisition including fees but prior to working capital and future income tax liability assumed on acquisition.
(8) Total assets and total liabilities have been restated for the retroactive application of change in accounting policy for asset retirement obligations.
(9) Includes other revenue.

CONSOLIDATED BALANCE SHEETS

As at March 31 and December 31 (unaudited)

($CDN thousands)	2005	2004
ASSETS		
Current assets		
Cash and cash equivalents	**$ -**	$ 4,413
Accounts receivable	**98,324**	72,881
Prepaid expenses	**11,572**	9,878
Commodity and foreign currency contracts (Note 5)	**2,970**	22,294
	112,866	109,466
Reclamation fund	**21,868**	21,294
Property, plant and equipment	**2,011,622**	2,016,646
Goodwill	**157,592**	157,592
Total assets	**$ 2,303,948**	$ 2,304,998
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 109,473**	$ 103,572
Cash distributions payable	**28,019**	27,893
Current portion of long-term debt (Note 3)	**8,467**	8,715
Commodity and foreign currency contracts (Note 5)	**73,699**	26,336
	219,658	166,516
Long-term debt (Note 3)	**218,189**	211,834
Other long-term liabilities (Note 4)	**3,823**	3,893
Asset retirement obligations	**73,200**	73,001
Future income taxes (Note 6)	**270,906**	300,406
Total liabilities	**785,776**	755,650
NON-CONTROLLING INTEREST		
Exchangeable shares (Note 7)	**35,765**	35,967
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 8)	**1,939,545**	1,926,351
Contributed surplus (Note 9)	**7,528**	6,475
Accumulated earnings	**917,453**	878,807
Accumulated cash distributions (Note 11)	**(1,382,119)**	(1,298,252)
Total unitholders' equity	**1,482,407**	1,513,381
Total liabilities and unitholders' equity	**$ 2,303,948**	$ 2,304,998

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED EARNINGS
For the three months ended March 31 (unaudited)

($CDN thousands, except per unit amounts)		2005		2004
				Restated (Note 2)
REVENUES				
Oil, natural gas, natural gas liquids and sulphur sales	**$**	**238,054**	$	205,594
Royalties		**(44,839)**		(38,757)
		193,215		166,837
Loss on commodity and foreign currency contracts (Note 5)		**74,001**		34,747
		119,214		132,090
EXPENSES				
Transportation		**3,586**		3,829
Operating		**30,441**		33,522
General and administrative		**6,166**		4,879
Non-cash trust unit incentive compensation (Notes 9 and 10)		**1,981**		2,845
Interest on long-term debt (Note 3)		**3,139**		2,618
Depletion, depreciation and accretion		**62,461**		58,612
Loss on foreign exchange		**1,027**		700
		108,801		107,005
Income before taxes		**10,413**		25,085
Capital taxes		**(650)**		(663)
Future income tax recovery (Note 6)		**29,500**		15,700
Net income before non-controlling interest		**39,263**		40,122
Non-controlling interest (Note 7)		**(617)**		(662)
Net income		**38,646**		39,460
Accumulated earnings, beginning of period		**878,807**		648,304
Accumulated earnings, end of period	**$**	**917,453**	$	687,764

Net income per unit (Note 12)				
Basic	**$**	**0.21**	$	0.22
Diluted	**$**	**0.20**	$	0.21

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the three months ended March 31 (unaudited)

($CDN thousands)		2005		2004
				Restated (Note 2)
CASH FLOW FROM OPERATING ACTIVITIES				
Net Income	**$**	**38,646**	$	39,460
Add items not involving cash:				
Non-controlling interest		**617**		662
Future income tax recovery		**(29,500)**		(15,700)
Depletion, depreciation and accretion		**62,461**		58,612
Non-cash loss on commodity and foreign currency contracts		**66,687**		16,475
Non-cash loss on foreign exchange		**1,073**		943
Amortization of commodity and foreign currency contracts		**-**		4,717
Non-cash trust unit incentive compensation		**1,981**		2,845
Funds from operations		**141,965**		108,014
Expenditures on site restoration and reclamation		**(1,047)**		(930)
Change in non-cash working capital		**(12,182)**		4,872
		128,736		111,956
CASH FLOW FROM FINANCING ACTIVITIES				
Issuance of long-term debt, net		**5,034**		12,451
Issue of trust units		**3,059**		12,954
Trust unit issue costs		**(2)**		-
Cash distributions paid, net of distribution reinvestment		**(75,045)**		(81,032)
Change in non-cash working capital		**1,847**		(241)
		(65,107)		(55,868)
CASH FLOW FROM INVESTING ACTIVITIES				
Acquisition of petroleum and natural gas properties		**(3,844)**		(1,679)
Proceeds on disposition of petroleum and natural gas properties		**176**		105
Capital expenditures		**(47,854)**		(59,860)
Net reclamation fund contributions		**(574)**		(1,676)
Change in non-cash working capital		**(15,946)**		(882)
		(68,042)		(63,992)
(DECREASE) IN CASH AND CASH EQUIVALENTS		**(4,413)**		(7,904)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**4,413**		12,295
CASH AND CASH EQUIVALENTS, END OF PERIOD	**$**	**-**	$	4,391

See accompanying notes to consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
March 31, 2005 and 2004 (unaudited)
(all tabular amounts in thousands, except per unit and volume amounts)

1. SUMMARY OF ACCOUNTING POLICIES

The unaudited interim consolidated financial statements follow the same accounting policies as the most recent annual audited financial statements. The interim consolidated financial statement note disclosures do not include all of those required by Canadian generally accepted accounting principles ("GAAP") applicable for annual financial statements. Accordingly, these interim financial statements should be read in conjunction with the audited consolidated financial statements included in the Trust's 2004 Annual Report.

2. RESTATEMENT OF PRIOR PERIODS DUE TO CHANGES IN ACCOUNTING POLICIES

As at December 31, 2004, the Trust adopted the following new accounting policy that required restatement of prior periods. The following explains the impact of this restatement on the Trust's previously reported financial statements for the first quarter of 2004.

Exchangeable Securities —Non-Controlling Interest

On January 19, 2005 the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" which requires that exchangeable securities issued by a subsidiary of an income trust should be reflected as either non-controlling interest or debt, as appropriate, in the consolidated balance sheet unless they meet certain criteria. EIC-151 states that if the exchangeable shares are transferable to a third party, they should be reflected as non-controlling interest or debt, as appropriate. The exchangeable shares issued by ARL, a corporate subsidiary of the Trust, are publicly traded and therefore must be recorded as non-controlling interest outside of Unitholders' Equity. Previously, the exchangeable shares were reflected as a component of Unitholders' Equity.

In accordance with the transitional provisions of EIC-151, retroactive application has been applied with restatement of prior periods. As a result of this change in accounting policy, the Trust has reflected non-controlling interest of $35.8 million and $36 million, respectively, in the Trust's consolidated balance sheet as at March 31, 2005 and December 31, 2004. Consolidated net income has been reduced for net income attributable to the non-controlling interest of $0.6 million and $0.7 million, respectively, for the first three months of 2005 and 2004. Opening accumulated earnings for 2004 were decreased by $11.2 million for the cumulative net income attributable to the non-controlling interest, Unitholders' Equity was reduced by $25.1 million and non-controlling interest on the consolidated balance sheet increased by $36.3 million. The new accounting policy resulted in a change in the calculation of weighted average trust units. Previously, weighted average trust units included outstanding exchangeable shares at the period end exchange ratio whereas under the new accounting policy, the weighted average trust units excludes trust units issuable for exchangeable shares. There was no change to net income per basic trust unit as a result of this change in accounting policy.

3. LONG-TERM DEBT

	March 31, 2005	December 31, 2004
Revolving credit facilities		
Working capital facility	**$ 5,299**	$ 290
Senior secured notes		
8.05% USD Note	**33,869**	33,701
4.94% USD Note	**36,288**	36,108
Long-term notes		
4.62% USD Note	**75,600**	75,225
5.10% USD Note	**75,600**	75,225
Total debt outstanding	**$ 226,656**	$ 220,549
Current portion of debt	**8,467**	8,715
Long-term debt	**$ 218,189**	$ 211,834

During the first quarter of 2005, the Trust renewed its syndicated revolving credit facility. Terms of the $620 million facility remained unchanged with the revolving syndicated credit facility having a 364 day extendable revolving period and a two year term. Borrowings under the facility bear interest at bank prime (4.25 per cent at March 31, 2005 and December 31, 2004) or, at the Trust's option, Canadian dollar or U.S. dollar bankers' acceptances plus a stamping fee. The lenders review the credit facility each year and determine whether they will extend the revolving periods for another year. The term date of the current credit facility is March 28, 2006.

In the event that the revolving periods are not extended, the loan balance will become repayable over a two year term period with 20 per cent of the loan balance outstanding on the term date payable on March 28, 2007 followed by three quarterly payments of five per cent of the loan balance. The remaining 65 per cent of the loan balance is payable in one lump sum at the end of the term period. Collateral for the loan is in the form of floating charges on all lands and assignments and negative pledges on specific petroleum and natural gas properties.

Interest paid during the year did not differ significantly from interest expense.

4. OTHER LONG-TERM LIABILITIES

	March 31, 2005	December 31, 2004
Retention bonuses	**$ 2,000**	$ 2,000
Accrued long-term incentive compensation	**1,823**	1,893
Total other long-term liabilities	**$ 3,823**	$ 3,893

The retention bonuses arose upon internalization of the management contract in 2002. The long-term portion of retention bonuses will be paid in August 2006 through August 2007.

The accrued long-term incentive compensation represents the long-term portion of the Trust's estimated liability for the Whole Unit Plan as at March 31, 2005 (see Note 10). This amount is payable in 2006 through 2007.

5. FINANCIAL INSTRUMENTS

The Trust uses a variety of derivative instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The Trust considers all of these transactions to be effective economic hedges, however, the majority of the Trust's contracts do not qualify as effective hedges for accounting purposes.

Following is a summary of all derivative contracts in place as at March 31, 2005:

Financial WTI Crude Oil Contracts

Term	Contract	Volume bbl/d	Swap US$/bbl	Bought Put US$/bbl	Sold Put US$/bbl	Sold Call US$/bbl
2005						
Apr 05 — Apr 05	3 Way[1]	2,000	-	47.32	42.00	52.00
May 05 — May 05	3 Way	2,000	-	47.32	29.00	57.50
Jun 05 — Jun 05	3 Way	2,000	-	47.32	29.00	63.00
Apr 05 — Dec 05	3 Way	500	-	34.00	30.00	41.75
Apr 05 — Jun 05	Max Payout	4,000	28.95	-	26.00	-
Apr 05 — Dec 05	Put Spread	2,000	-	47.05	29.00	-
Apr 05 — Dec 05	Put Spread	1,000	-	46.65	33.00	-
Apr 05 — Dec 05	Put Spread	3,500	-	46.36	30.00	-
Jul 05 — Dec 05	Put Spread	2,000	-	47.32	29.00	-
Jul 05 — Dec 05	Swaption[2]	4,000	28.95	-	-	-
2005 Weighted Average		**13,000**	**28.95**	**46.07**	**29.67**	**50.72**
2006						
Jan 06 — Mar 06	3 Way	2,000	-	36.00	29.00	40.00
Jan 06 — Mar 06	Bought Put	2,000	-	50.00	-	-
Jan 06 — Jun 06	Put Spread	2,000	-	50.00	40.00	-
Apr 06 — Jun 06	3 Way	2,000	-	36.00	29.00	40.65
2006 Weighted Average		**2,477**	**-**	**44.39**	**34.50**	**40.33**

(1) Includes additional embedded sold put at US$29 (CDN $35.08).

(2) Counterparty can exercise their option on June 30, 2005 for a fixed price swap at US$28.95 (CDN $35.02) for the period July through December 2005.

Financial AECO Natural Gas Contracts

Term	Contract	Volume GJ/d	Swap CDN$/GJ	Bought Put CDN$/GJ	Sold Put CDN$/GJ	Sold Call CDN$/GJ
2005						
Apr 05 — Apr 05	Bought Put	10,000	-	6.63	-	-
Apr 05 — Apr 05	Put Spread	10,000	-	6.99	5.50	-
Apr 05 — Apr 05	Put Spread	10,000	-	7.42	5.50	-
May 05 — May 05	3 Way	10,000	-	6.65	5.50	7.25
May 05 — May 05	3 Way	10,000	-	6.63	5.55	7.25
Jun 05 — Jun 05	Collar	10,000	-	6.65	-	8.00
Jun 05 — Jun 05	Collar	10,000	-	6.63	-	7.75
Jul 05 — Jul 05	Collar	10,000	-	6.65	-	8.00
Jul 05 — Jul 05	Collar	10,000	-	6.63	-	8.25
Apr 05 — Oct 05	3 Way	10,000	-	6.00	5.00	8.00
Apr 05 — Oct 05	3 Way	5,000	-	6.50	5.50	7.55
Apr 05 — Oct 05	3 Way	5,000	-	6.50	5.50	8.00
Apr 05 — Oct 05	Bought Put	5,000	-	6.75	-	-
Apr 05 — Oct 05	Bought Put	10,000	-	6.85	-	-
Apr 05 — Oct 05	Collar	10,000	-	6.42	-	8.00
Apr 05 — Oct 05	Collar	10,000	-	6.65	-	8.00
May 05 — Oct 05	Bought Put	10,000	-	6.99	-	-
May 05 — Oct 05	Bought Put	10,000	-	7.42	-	-
Aug 05 — Oct 05	Bought Put	10,000	-	6.65	-	-
Aug 05 — Oct 05	Bought Put	10,000	-	6.63	-	-
2005 Weighted Average		**72,836**		**6.68**	**5.31**	**7.91**

Financial Natural Gas NYMEX Contracts

Term	Contract	Volume mmbtu/d	Swap US$/mmbtu	Bought Put US$/mmbtu	Sold Put US$/mmbtu	Sold Call US$/mmbtu
2005						
Apr 05 — Oct 05	Collar	10,000	-	6.50	-	8.00
Apr 05 — Oct 05	Collar	10,000	-	6.50	-	8.00
2005 Weighted Average		**15,564**	**-**	**6.50**	**-**	**8.00**

Financial Natural Gas AECO Basis Contracts

Term	Contract	Volume mmbtu/d	Swap US$/mmbtu
2005			
Apr 05 —Oct 05	Swap	10,000	(0.865)
Apr 05 —Oct 05	Swap	10,000	(0.840)
2005 Weighted Average		**15,564**	**(0.853)**

Financial Foreign Exchange Contracts

Term	Contract	Volume MM US$	Swap CDN$/US$	Swap US$/CDN$
USD Sales Contracts				
2005				
Apr 05 —Oct 05	Swap	27.7	1.2384	0.8075
Apr 05 —Dec 05	Swap	26.9	1.2153	0.8228
Apr 05 —Dec 05	Swap	40.8	1.2115	0.8254
Apr 05 —Dec 05	Swap	21.5	1.2169	0.8218
Apr 05 —Dec 05	Swap	32.2	1.2000	0.8333
Total and 2005 Weighted Average		**149.1**	**1.2155**	**0.8227**
2006				
Jan 06 —Jun 06	Swap	6.5	1.2115	0.8254
Jan 06 —Jun 06	Swap	6.5	1.2000	0.8333
Total and 2006 Weighted Average		**6.5**	**1.2058**	**0.8294**
USD Purchase Contracts				
2005				
Apr 05 —Dec 05	Swap	12.0	1.1966	0.8357

Financial Electricity Contracts[1]

Term	Contract	Volume MWh	Swap CDN$/MWh
Apr 05 —Dec 10	Swap	5.0	63.00

(1) Contracted volume is based on a 24/7 term.

Financial Interest Rate Contracts [1]

Term	Contract	Principal MM US$	Fixed Annual Rate (%)	Spread on 3 Mo. LIBOR
Apr 05 — Apr 14	Swap	30.5	4.62	38.5 bps
Apr 05 — Apr 14	Swap	32.0	4.62	38 bps
Total and Annual Weighted Average		**62.5**	**4.62**	**38.2 bps**

(1) Interest rate swap contracts have an optional termination date of April 27, 2009. The Trust has the option to extend the optional termination date by one year on the anniversary of the trade date each year until April 2009. Starting in 2009, the contract amount decreases annually until 2014. The Trust pays the floating interest rate based on the three month LIBOR plus a spread and receives the fixed interest rate.

The Trust has designated its fixed price electricity contract as an effective accounting hedge as at January 1, 2004. A realized loss of $0.2 million for the first three months of 2005 on the electricity contract has been included in operating costs. The fair value unrealized loss on the electricity contract of $2.1 million has not been recorded on the consolidated balance sheet at March 31, 2005.

The Trust has entered into interest rate swap contracts to manage the Company's interest rate exposure on debt instruments. These contracts have been designated as effective accounting hedges on the contract date. A realized gain of $0.3 million for the first three months of 2005 on the interest rate swap contracts has been included in interest expense. The fair value unrealized loss on the interest rate swap contracts of $1.6 million has not been recorded on the consolidated balance sheet at March 31, 2005.

None of the Trust's commodity and foreign currency contracts have been designated as effective accounting hedges. Accordingly, all commodity and foreign currency contracts have been accounted for as assets and liabilities in the consolidated balance sheet based on their fair values.

The following table reconciles the movement in the fair value of the Trust's financial commodity and foreign currency contracts that have not been designated as effective accounting hedges:

	March 31, 2005	March 31, 2004
Fair value, beginning of period (1)	**$ (4,042)**	$ (14,575)
Fair value, end of period (1)	**(70,729)**	(1,900)
Change in fair value of contracts in the period	**(66,687)**	(16,475)
Realized losses in the period	**(7,314)**	(11,142)
Non-cash amortization of crystallized hedging gains	**-**	(7,130)
Loss on commodity and foreign currency contracts (1)	**$ (74,001)**	$ (34,747)

	March 31, 2005	December 31, 2004
Commodity and foreign currency contracts liability	**$ (73,699)**	$ (26,336)
Commodity and foreign currency contracts asset	**$ 2,970**	$ 22,294

(1) Excludes the fixed price electricity contract and interest rate swap contracts that were accounted for as effective accounting hedges.

At March 31, 2005, the fair value of the contracts that were not designated as accounting hedges was a loss of $70.7 million. The Trust recorded a loss on commodity and foreign currency contracts of $74 million and $34.7 million in the statement of income for the first three months of 2005 and 2004, respectively. This amount includes the realized and unrealized gains and losses on derivative contracts that do not qualify as effective accounting hedges.

6. INCOME TAXES

The future income tax recovery of $29.5 million in the first quarter of 2005 included a recovery of $22.8 million due to the unrealized loss of $66.7 million on commodity and foreign currency contracts. In the first quarter of 2004, the future income tax recovery of $15.7 million included a recovery of $8.2 million for the $23.6 million unrealized loss on commodity and foreign currency contracts and a one time recovery of $3.2 million due to the change in Alberta corporate income tax rates which were enacted in 2004.

The Trust's future tax rate applicable to temporary differences currently approximates 34 per cent.

On March 23, 2005, Saskatchewan Finance passed its 2005 budget which included an amendment to the Corporation Capital Tax Resource Surcharge ("Resource Surcharge"). Previously, the resource surcharge did not apply to resource trusts or resource corporations affiliated with resource trusts and therefore the Trust was not impacted by the resource surcharge. However, due to the increasing number of oil and gas producers operating in Saskatchewan through a trust structure, the Saskatchewan government passed legislation to make the resource surcharge applicable to resource trusts effective April 1, 2005. The resource surcharge is calculated based on a rate applicable to working interest oil and natural gas revenue earned in Saskatchewan. A rate of 3.6 per cent is applied to working interest revenue from wells drilled prior to October 1, 2002 and a rate of two per cent of working interest revenue from wells drilled on or after October 1, 2002. Approximately 25 per cent of the Trust's current operations are in Saskatchewan. The Trust has estimated that the new tax will approximate $2 million per quarter in 2005, commencing in the second quarter.

7. EXCHANGEABLE SHARES

ARL EXCHANGEABLE SHARES	**March 31, 2005**	March 31, 2004
Balance, beginning of period	**1,784**	2,011
Exchanged for trust units (1)	**(40)**	(39)
Balance, end of period	**1,744**	1,972
Exchange ratio, end of period	**1.71265**	1.53618
Trust units issuable upon conversion, end of period	**2,986**	3,029

(1) During the first three months of 2005, 40,381 ARL exchangeable shares were converted to trust units at an average exchange ratio of 1.69496.

Following is a summary of the non-controlling interest for March 31, 2005 and December 31, 2004:

		March 31, 2005		December 31, 2004
Non-controlling interest, beginning of period	**$**	**35,967**	$	36,311
Reduction of book value for conversion to trust units		**(819)**		(4,295)
Current period net income attributable to non-controlling interest		**617**		3,951
Non-controlling interest, end of period	**$**	**35,765**	$	35,967
Accumulated earnings attributable to non-controlling interest	**$**	**15,756**	$	15,139

8. UNITHOLDERS' CAPITAL

	March 31, 2005		December 31, 2004	
TRUST UNITS ISSUED	**Number of Trust Units**	**$**	Number of Trust Units	$
Balance, beginning of period	**185,822**	**1,926,351**	179,780	1,843,112
Issued for properties	**-**	**-**	2,032	30,500
Issued on conversion of ARL exchangeable shares (Note 7)	**68**	**819**	363	4,295
Issued on exercise of employee rights (Note 9)	**226**	**3,353**	1,751	20,672
Distribution reinvestment program	**507**	**9,024**	1,896	27,924
Trust unit issue costs	**-**	**(2)**	-	(152)
Balance, end of period	**186,623**	**1,939,545**	185,822	1,926,351

9. TRUST UNIT INCENTIVE RIGHTS PLAN

A summary of the changes in rights outstanding under the plan is as follows:

	Weighted Number of Rights	**Average Exercise Price ($)**
Balance, beginning of period	**3,009**	**10.92**
Exercised	**(226)**	**12.07**
Cancelled	**(60)**	**11.25**
Balance before reduction of exercise price	**2,723**	**10.93** (1)
Reduction of exercise price	**-**	**(0.18)**
Balance, end of period	**2,723**	**10.75** (1)

(1) The holder of the right has the option to exercise rights held at the original grant price or a reduced exercise price.

The Trust recorded compensation expense of $1.7 million and $2.9 million for the first three months of 2005 and 2004, respectively, for the cost associated with the rights. The compensation expense was based on the fair value of rights issued after January 1, 2003 which were outstanding in the first quarter of 2005 and is amortized over the remaining vesting period of such rights. Of the 3,013,569 rights issued on or after January 1, 2003 that were subject to recording compensation expense, 242,533 rights have been cancelled and 682,462 rights have been exercised to March 31, 2005.

The following table reconciles the movement in the contributed surplus balance:

CONTRIBUTED SURPLUS	March 31, 2005	December 31, 2004
Balance, beginning of period	**$ 6,475**	$ 3,471
Compensation expense	**1,674**	5,171
Net benefit on rights exercised [1]	**(621)**	(2,167)
Balance, end of period	**$ 7,528**	$ 6,475

[1] Upon exercise, the net benefit is reflected as a reduction of contributed surplus and an increase to unitholders' capital.

Pro Forma Results	March 31, 2004	March 31, 2003
Net income as reported	**$ 38,646**	$ 39,460
Less: compensation expense for rights issued in 2002	**4,746**	1,070
Pro forma net income	**33,900**	38,390
Basic net income per trust unit		
As reported	**$ 0.21**	$ 0.22
Pro forma	**$ 0.18**	$ 0.21
Diluted net income per trust unit		
As reported	**$ 0.20**	$ 0.21
Pro forma	**$ 0.18**	$ 0.21

10. WHOLE TRUST UNIT INCENTIVE PLAN

The Trust recorded compensation expense of $0.7 million in the first three months of 2005 (nil in the first three months of 2004) for the estimated cost of the plan. The compensation expense was based on the March 31, 2005 unit price of $18.15, distributions of $0.15 per unit per month during the quarter, and management's estimate of the number of Restricted Trust Units ("RTU") and Performance Trust Units ("PTU") to be issued on maturity. The following table summarizes the RTU and PTU movement for the three months ended March 31, 2005.

	Number of RTU's	Number of PTU's
Balance, beginning of period	224	128
Granted	-	-
Forfeited	(5)	(4)
Balance, end of period	219	124

11. RECONCILIATION OF CASH FLOW AND DISTRIBUTIONS

Cash distributions are calculated in accordance with the Trust Indenture. To arrive at cash distributions, cash flow from operations, before changes in non-cash working capital, is reduced by reclamation fund contributions including interest earned on the fund, a portion of capital expenditures, and debt repayments. The portion of cash flow withheld to fund capital expenditures and to make debt repayments is at the discretion of the Board of Directors.

	March 31, 2005	March 31, 2004
Cash flow from operations before changes in non-cash working capital	**$ 141,965**	$ 108,014
Add (deduct):		
Cash withheld to fund current period capital expenditures	**(52,520)**	(25,123)
Reclamation fund contributions and interest earned on fund	**(1,718)**	(1,676)
Discretionary debt repayments	**(3,860)**	-
Cash distributions	**83,867**	81,215
Accumulated cash distributions, beginning of period	**1,298,252**	968,275
Accumulated cash distributions, end of period	**$ 1,382,119**	$ 1,049,490
Cash distributions per unit [1]	**$ 0.45**	$ 0.45
Accumulated cash distributions per unit, beginning of year	**14.24**	12.44
Accumulated cash distributions per unit, end of period	**$ 14.69**	$ 12.89

[1] Cash distributions per trust unit reflect the sum of the per trust unit amounts declared monthly to unitholders.

12. BASIC AND DILUTED PER TRUST UNIT CALCULATIONS

Net income per trust unit has been determined based on the following:

	2005	2004[4]
Weighted average trust units [1]	**186,224**	180,285
Trust units issuable on conversion of exchangeable shares [2]	**2,986**	3,029
Dilutive impact of rights [3]	**1,714**	1,682
Diluted trust units	**190,924**	184,996

(1) Weighted average trust units excludes trust units issuable for exchangeable shares.
(2) Diluted trust units include trust units issuable for outstanding exchangeable shares at the period end exchange ratio.
(3) All outstanding rights were dilutive and therefore none have been excluded in the diluted trust unit calculation.
(4) 2004 weighted average trust units have been restated to exclude trust units issuable for exchangeable shares in accordance with retroactive change in accounting policy for non-controlling interest.

13. COMMITMENTS AND CONTINGENCIES

Following is a summary of the Trust's contractual obligations and commitments due by period as at March 31, 2005:

($ millions)	2005	2006-2007	2008-2009	Thereafter	Total
Debt repayments [1]	8.5	36.7	35.6	145.9	226.7
Operating leases	2.7	4.9	4.2	2.1	13.9
Purchase commitments	4.0	3.4	2.7	8.0	18.1
Retention bonuses	1.0	2.0	-	-	3.0
Derivative contract premiums [2]	25.7	2.6	-	-	28.3
Total contractual obligations	41.9	49.6	42.5	156	290

(1) Includes long-term and short-term debt.
(2) Fixed premiums to be paid in future periods on certain commodity derivative contracts.

In addition to the above, the Trust has commitments related to its risk management program (See Note 5).

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that the Trust has committed to approximately $40 to $60 million of capital expenditures by means of giving the necessary authorizations to incur the capital in a future period. This commitment has not been disclosed in the commitment table above as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that pending litigation will not have a material adverse impact on the Trust's financial position or results of operations.

CORPORATE AND UNITHOLDER INFORMATION

DIRECTORS

Mac H. Van Wielingen (1) (3) (4)
Chairman

Walter DeBoni (1) (4) (5)
Vice-Chairman

John P. Dielwart
President and Chief Executive Officer

John M. Beddome (2) (4)

Frederic C. Coles (2) (3) (5)

Fred J. Dyment (1) (2)

Michael M. Kanovsky (1) (2)

John M. Stewart (3) (4) (5)

(1) Member of Audit Committee
(2) Member of Reserve Audit Committee
(3) Member of Human Resources and Compensation Committee
(4) Member of Policy and Board Governance Committee
(5) Health, Safety and Environment Committee

OFFICERS

John P. Dielwart
President and Chief Executive Officer

Doug J. Bonner
Vice-President, Engineering

David P. Carey
Vice-President, Business Development

Susan D. Healy
Vice-President, Corporate Services

Steven W. Sinclair
Vice-President, Finance and Chief Financial Officer

Myron M. Stadnyk
Vice-President, Land and Operations

Allan R. Twa
Corporate Secretary

EXECUTIVE OFFICE

ARC Resources Ltd.
2100, 440 – 2nd Avenue S.W.
Calgary, Alberta T2P 5E9

Telephone: (403) 503-8600
Toll Free: 1-888-272-4900
Facsimile: (403) 503-8609
Website: www.arcenergytrust.com
E-Mail: ir@arcresources.com

TRUSTEE AND TRANSFER AGENT

Computershare Trust Company of Canada
600, 530 – 8th Avenue S.W.
Calgary, Alberta T2P 3S8
Telephone: (403) 267-6800

AUDITORS

Deloitte & Touche LLP
Calgary, Alberta

ENGINEERING CONSULTANTS

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

LEGAL COUNSEL

Burnet Duckworth & Palmer LLP
Calgary, Alberta

Canada's Climate Change Voluntary Challenge and Registry. The industry's voluntary effort to reduce greenhouse gas emissions and document the efforts year over year.

CORPORATE CALENDAR

2005	
July 15	Announcement of Q3 Distribution Monthly Amounts
August 4	2005 Q2 Results
October 17	Announcement of Q4 Distribution Monthly Amounts
November 3	2005 Q3 Results

STOCK EXCHANGE LISTING

The Toronto Stock Exchange

Trading Symbols:
AET.UN (Trust Units)
ARX (Exchangeable Shares)

INVESTOR INFORMATION

Visit our website at
www.arcresources.com
or www.arcenergytrust.com
or contact:
Investor Relations
(403) 503-8600 or
1-888-272-4900 (Toll Free)

PRIVACY OFFICER

Susan D. Healy
privacy@arcresources.com
Facsimile: (403) 509-7260

Members commit to continuous improvement in the responsible management, development and use of our natural resources; protection of our environment; and, the health and safety of our workers and the general public

NOTES

ARC ENERGY TRUST